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ENVIRONMENTAL HEALTH SERIES
Water Supply
and Pollution Control

ULTIMATE DISPOSAL of Advanced-Treatment Waste

Part 1. Injection

Part 2. Placement in Underground Cavities

Part 3. Spreading

AWTR-8

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Public Health Service

ULTIMATE DISPOSAL BY INJECTION, PLACEMENT UNDERGROUND, AND SPREADING

Advanced Waste Treatment Research Publications

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		Report Number
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AWTR-3	Ultimate Disposal of Advanced-Treatment Waste Part 1. Wet Oxidation Part 2. Incineration	999-WP-3
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AWTR-8	Ultimate Disposal of Advanced-Treatment Waste Part 1. Injection Part 2. Placement in Underground Cavities Part 3. Spreading	999-WP-10

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ULTIMATE DISPOSAL
of Advanced-Treatment Waste

Part 1. Injection

Part 2. Placement in Underground Cavities

Part 3. Spreading

by

Louis Koenig-Research

for

The Advanced Waste Treatment Research Program
Basic and Applied Sciences Branch
Robert A. Taft Sanitary Engineering Center

A combination of reports submitted in fulfillment of contracts between the Public Health Service and Louis Koenig-Research, San Antonio, Texas (Purchase Order Nos. 1681 and 1682). Parts 1, 2, and 3 were submitted in November 1961, March 1962, and May 1962 respectively.

U.S. DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Public Health Service
Division of Water Supply and Pollution Control

May 1964

The ENVIRONMENTAL HEALTH SERIES of reports was established to report the results of scientific and engineering studies of man's environment: The community, whether urban, suburban, or rural, where he lives, works, and plays; the air, water, and earth he uses and re-uses; and the wastes he produces and must dispose of in a way that preserves these natural resources. This SERIES of reports provides for professional users a central source of information on the intramural research activities of Divisions and Centers within the Public Health Service, and on their cooperative activities with State and local agencies, research institutions, and industrial organizations. The general subject area of each report is indicated by the two letters that appear in the publication number; the indicators are

WP - Water Supply and Pollution Control

AP - Air Pollution

AH - Arctic Health

EE - Environmental Engineering

FP - Food Protection

OH - Occupational Health

RH - Radiological Health

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Public Health Service Publication No. 999-WP-10

ADVANCED WASTE TREATMENT RESEARCH PROGRAM

The Advanced Waste Treatment Research Program of the Public Health Service has two ultimate goals: One is to help abate our Nation's growing water pollution problems, and the other, more startling in concept, is to renovate waste water for direct and deliberate re-use.

Conventional water and waste treatment practices have little or no effect on many simple inorganic salts and permit an ever-increasing number and amount of highly complex, synthetic organic wastes to contaminate drinking water supplies. If we are to protect these water supplies for the future, it is mandatory that new technologies for water and waste treatment be developed.

Advanced Waste Treatment may be looked upon as a two-step process: (1) Separating concentrated contaminants from the purified water "product," and (2) disposing of the concentrated contaminants in a way that will render them forever innocuous. This "permanent disposal" of separated wastes is essential so that useable surface or ground waters will not be contaminated and so that the same contaminants need not be removed again and again from water supplies.

In one step, then, advanced waste treatment, i.e., water renovation, could alleviate both water pollution and water supply problems – problems of increasing concern both in this country and in the rest of the world. The importance of advanced waste treatment was recognized by Congress in its 1961 amendments to the Federal Water Pollution Control Act (Public Law 87-88). This act directs the Secretary of Health, Education, and Welfare "... to develop and demonstrate practicable means of treating municipal sewage and other water-borne wastes to remove the maximum possible amounts of physical, chemical, and biological pollutants in order to restore and maintain the maximum amount of the Nation's water at a quality suitable for re-use."

It is too early to predict accurately the cost of advanced waste treatment technology, but the need is inevitable. Because of population increase and industrial expansion, we are approaching the time when our rivers and streams will no longer be able to assimilate our wastes and when there will be no more developable supplies of fresh water. Whatever the cost of this technology, one thing is certain – it must be the very lowest science and engineering can achieve. Anything more will impose an inexcusable, perhaps intolerable burden on our country's economic growth and on its ability to compete in tomorrow's world.

The author of this report, Dr. Louis Koenig, has specialized in waste treatment and disposal and their economics for several years. He has been involved in research projects on the injection of natural brines in the Arkansas-Red River Basin and on several processes for disposing of saline-water conversion wastes. He has also studied, for the AWTR Program, wet oxidation and incineration as ultimate disposal techniques.

PREFACE

Under the Advanced Waste Treatment Research Program, the U. S. Public Health Service is engaged in a study of processes that might be used to treat various waters or waste waters to make them re-usable. Some of the processes would completely remove or destroy the contaminants, while others would leave the original contaminants as a waste to be disposed of. The processes for dealing with this waste are termed "ultimate disposal." Ultimate disposal means the treatment, handling, or placement of a waste in such a manner that it never again comes in contact with human activity other than, in certain instances, a very small surveillance or containment activity. These reports present the results of preliminary studies of three methods of ultimate disposal of the contaminants, namely injection, placement in underground cavities, and spreading. The work was instituted under Purchase Order No. 1681 and 1682 between the Robert A. Taft Sanitary Engineering Center and Louis Koenig-Research, covering a scope as follows:

> "Assess the physical, natural and economic parameters which might bear on the costs, physical magnitudes, and general feasibility of ultimate disposal of advanced treatment wastes by injection, placement in underground cavities, and spreading. Determine by preliminary cost estimation for reasonable ranges of these parameters, the costs and physical magnitudes involved especially as these are influenced by volume and concentration of waste. Point out areas in which further research or data collection would be necessary in order to make a similar estimate of the next order of accuracy."

A report on ultimate disposal of advanced-treatment wastes by wet oxidation and by incineration has been published. (Public Health Service Publication No. 999-WP-3, AWTR-3.)

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ABSTRACT

Cost estimates are made for ultimate disposal of the contaminants resulting from complete renovation of a municipal waste water. The processes investigated are: Injection to underground formations, placement in underground cavities, and spreading.

Part 1. For injection, capability was the strongest determinant of conditioning and injecting costs. These costs varied from $0. 13 to $27 per 1, 000 gallons injected (7, 000 ft. , 260 psi wellhead pressure, 1. 187 fluid density) as the capability decreased from 2 million to 1, 000 gallons per day. The disposal cost is relatively independent of concentration. Injection is very much cheaper than wet oxidation, but may be limited by availability of injection sites. (16 figures, 41 references.)

Part 2. Disposal of advanced-treatment wastes in salt cavities created for such use is inapplicable because the difficulty of disposing of the salt removed is greater than that of disposing of the waste. For cavities mined by conventional methods, fixed costs alone vary from $243 to $72 per 1, 000 gallons at capabilities of 1, 000 and 10 million gallons per day, respectively. Costs for disposal in cavities created by nuclear blasting are highly speculative. Fixed costs vary from $139 to $0. 269 per 1, 000 gallons as the capability increases from 1, 000 to 10 million gallons per day. Disposal to cavities created by mineral mining is considered. Feasibility depends upon geographical distribution. Injection is preferable to placement in cavities where possible. (3 figures, 16 references.)

Part 3. Spreading is by far the cheapest disposal method. Costs varied from $0. 30 to $0. 001 per 1, 000 gallons as the capability varied from 1, 000 (0. 4-foot-per-day infiltration rate) to 10 million gallons per day (4. 0-feet-per-day infiltration rate). Land costs between $25 and $1000 per acre were considered and, in this range, had very little effect on over-all cost. The costs are 1 percent or less of those for any other disposal method investigated, but spreading is severely limited in application because of potential ground water pollution. (3 figures, 21 references.)

ULTIMATE DISPOSAL BY INJECTION

Part 1.

INJECTION

Summary

In some of the advanced waste treatment processes for the production of water, the water is extracted from the raw material, or contaminants are removed therefrom to yield the ultimate product and a waste stream consisting of the contaminants and possibly some of the reagents in a more or less concentrated form. A preliminary process design and cost estimate was made for ultimate disposal of these liquid wastes by injection to underground formations. The process parameters were concentration of contaminants and daily volume taken respectively as 300,000, 9,000, and 300 parts per million (ppm) total organic and inorganic contaminants, and 1,000, 100,000 and 10 million gallons per day (gpd). Parameters introduced by the injection situation were depth of well and existing wellhead pressure, exclusive of casing friction drop, which were taken respectively as 3,000, 7,000, and 12,000 feet, and 0, 260, and 900 pounds per square inch (psi). Technological limitations of injection wells restricted the highest capability parameter to 2,000 gpd, capabilities beyond this being achieved by replication. Cases were computed for the 81 combinations of these parameters.

An estimating system was devised for summing 14 components of injection well costs to achieve costs that reproduced within 10 percent the average U.S. cost of oil and gas wells at any depth up to 15,000 feet.

The effect of well diameter on the cost of these components was developed so that synthetic costs could be produced for wells much larger than and much smaller than are common in oil field practice, as will be required for injection practice. The costs of pumping equipment and pumping operation for injection were developed. From the preceding data the economic diameters were determined for injection wells at the various capabilities, depths, concentrations, and pressures. These were from 8-5/8 to 10-3/4 inches production casing for the 2,000 gpd well, 2-7/8 to 4-1/2 inches for 100,000 gpd, and 2-7/8 inches, the lower technological limit, for 1,000 gpd.

Investment and operating costs were developed for conditioning wastes for injection according to the simple treatment measures used in the oil fields. These were combined with the cost of injection to determine conditioning and injection costs in terms of dollars per 1,000 gallons, dollars per day, and dollars investment per gallon per day.

These costs varied from a low of \$0.0079 per 1,000 gallons for 2,000 gpd, 3,000 feet, 0 psi, and 300,000 ppm concentration (1.187 density) to a high of about \$58 per 1,000 gallons for 1,000 gpd, 900 psi, 12,000 feet, and 9,000 ppm (1.005 density). Capability had the greatest effect on unit costs with depth next, pressure next, and concentration last.

Unit investment costs varied from \$0.024 to \$213.2 per gallon per day of capability.

Fixed costs as percent of total disposal costs varied little with pressure and concentration, increased with depth, and decreased at increasing capabilities. For 1,000 gpd this factor was in the 80 to 95 percent range; for 2 million gpd, 16 to 48 percent; and for 100,000 gpd, 50 to 80 percent.

For a given set of parameters, chosen for illustration as 7,000 feet and 900 psi, the daily disposal costs were almost entirely a function of capability and were practically independent of the tons per day of contaminants. For the typical case they were as follows:

gpd	1,000	10,000	100,000	1 million	2 million	10 million
$/day	27	44	57	230	420	1,200

Compared with wet oxidation as an ultimate disposal method, 10,000 gpd could be disposed by injection for the same cost as 1,000 gpd by wet oxidation, and 2 million gpd, for the same cost as 100,000 gpd by wet oxidation.

For example, the daily cost of injection for advanced-treatment processes was computed for a community of 60,000 population producing 10 million gpd of a 300 ppm feed to the advanced-treatment process. The cost of disposal by injection per million gallons of water produced in the advanced-treatment plant would be \$196 at 50 percent recovery and \$50 at 80 percent recovery. This latter compares with \$540 for disposal by wet oxidation. At 99.9 percent recovery, which would produce a waste of the upper limiting concentration, the cost for disposal by injection would be \$3.20 per million gallons. The conclusion is that reasonable disposal costs can be achieved by injection at very much lower recoveries than by wet oxidation.

A number of areas were suggested for improving the present study by modifications of technique and parameters, and by improvement of the basic data. For future studies on the applicability of injection to advanced-treatment waste disposal there were suggested: A study of the geographical occurrence of suitable injection formations and an evaluation of their parameters significant for injection; a fundamental study of reservoir mechanics as applied to long-term injection of fluids to completely closed reservoirs; and a continuing analysis of whether conditioning, which is a significant part of disposal costs, might not be more cheaply incorporated in some phase of the advanced-treatment processes themselves.

Experienced Well Construction Costs

Fairly comprehensive statistics on well costs are now compiled annually by a joint effort of the American Petroleum Institute, the Independent Petroleum Association of America (IPAA), and the Mid-Continent Oil and Gas Association. Figure 1 shows the Joint Association data for national average costs of oil and gas wells as a function of depth for the years 1953, 1956, and 1959, all corrected to 1961 conditions by application of the (anticipated) 1961 IPAA index of rotary drilling and completion costs per foot.[4] The index is anticipated prior to its compilation for 1961 at 152.0 (1947-49 = 100). Reasonably close agreement for the three years is shown.

REGIONAL VARIATIONS

The data dealt with in the previous section cover the entire United States. It is pertinent to inquire whether variations in these per-foot costs from region to region might not be so great as to make the composite data of no value.

The Joint Association Survey of Industry Drilling Costs, 1959,[3] breaks down costs by state or region and by depth classification in each. One might compare the average per foot construction cost in each region with the United States average, except that the distributions of wells by depth in the various regions are not the same and such a regional average would include the effect of depth as well as that of any regional variation. Accordingly it seems most logical to compare per foot costs for wells of the same depth. The comparison might differ according to the depth chosen. Since all depths could not be

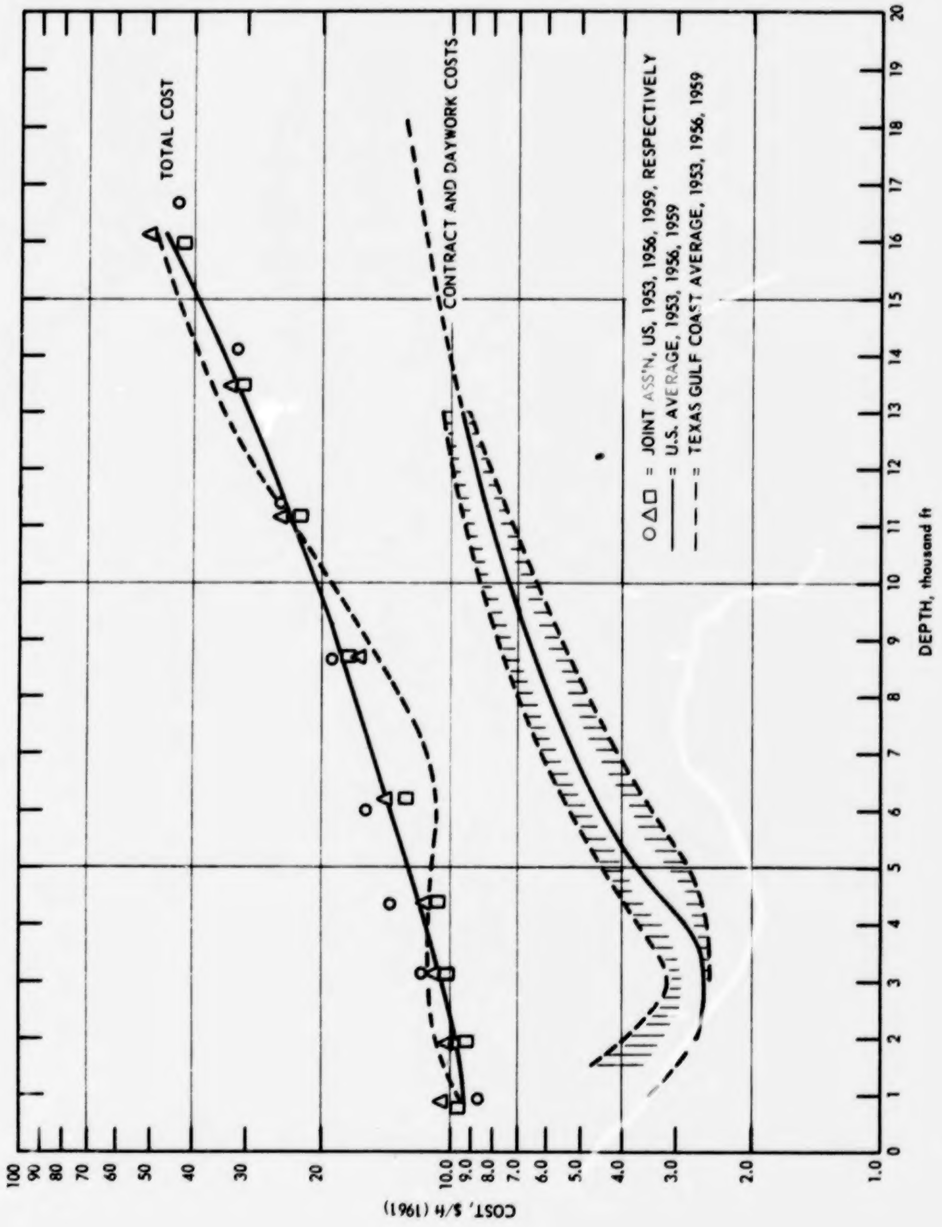


Figure 1. Cost of oil and gas wells.

covered in the present study, choice was made of the 5,001- to 7,500-foot depth classification, which corresponds to the depth visualized for a typical ultimate-disposal well.

From the 1959 survey the total number of wells, total footage, total cost, and from these, the average depth and the average dollars per foot cost were computed. From the 1959 curve, similar to Figure 1, was read the U.S. average dollars per foot cost at each state average depth in the depth class, and from this corresponding U.S. cost was computed an index number on the basis U.S. = 100. These index numbers are shown in Figure 2.

There is a moderate regional variation, in general increasing from south to north and from east to west. The average deviation from the average for the 26 regions (excluding Alaska) is 16 percent.

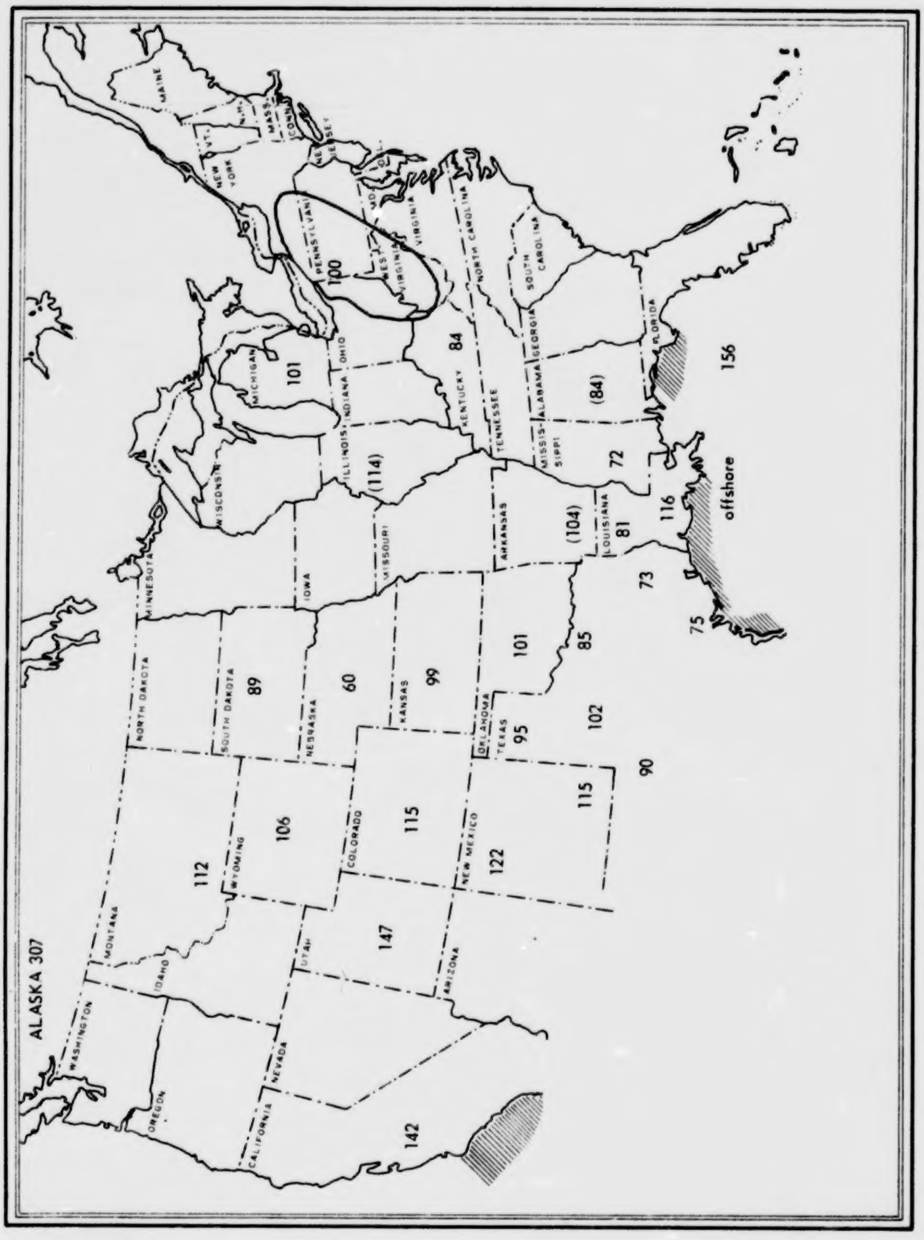
The Arkansas figure computed according to the method given was 154, but, since this seemed quite out of line with its neighbors, a special analysis was made. It developed that in the 5,001- to 7,500-foot depth classification in Arkansas the number of gas wells was 100 percent of the number of oil wells compared with only 20 percent for the national average. Furthermore, in Arkansas, for some reason, gas wells are much more expensive than oil wells, and in the depth classification of interest, the cost was 70 percent greater than the average oil well per foot compared with 10 percent greater for the national average. Accordingly for Arkansas only the oil wells in the depth category were used in arriving at the index number. The other parentheses on the Figure indicate regions in which the data encompassed only a very small number of wells compared with the other regions.

Figure 2 may also provide approximate correction factors for adjusting well costs for the United States to well costs in the particular region of interest.

It should be noted that, as shown by the Texas Gulf Coast line in Figure 1, the index number for any region may vary with the well depth.

Components Of Well Construction Costs

Practice in the construction of oil wells and injection wells varies depending upon circumstances but usually may be broken into two broad categories, "contract costs" and "owners' costs." Contract costs refers to the contract ordinarily drawn between


ALASKA 307
WASHINGTON
OREGON
CALIFORNIA
142
NEVADA
IDAHO
MONTANA
112
UTAH
147
ARIZONA
WYOMING
106
COLORADO
115
NEW MEXICO
122
NORTH DAKOTA
SOUTH DAKOTA
89
NEBRASKA
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KANSAS
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OKLAHOMA
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75
73
MINNESOTA
IOWA
MISSOURI
ARKANSAS
(104)
LOUISIANA
81
116
offshore
WISCONSIN
ILLINOIS
(114)
MICHIGAN
101
INDIANA
OHIO
KENTUCKY
84
TENNESSEE
MISSIS-SIPPI
72
ALABAMA
(84)
GEORGIA
FLORIDA
156
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
100
MD.
NEW JERSEY
NEW YORK
VT.
N.H.
MASS.
CONN.
MAINE

Figure 2. Relative costs per foot of oil and gas wells, by region (5,991 to 7,500 ft deep, constructed in 1959, U.S. average = 100).

the well owner (usually called operator in oil field terminology) and a drilling contractor. This calls for performance of certain of the well construction operations and the bearing of certain of these costs. Typical operations included in contractors' costs are the following:

Prepare site
move rig on and off (from a comparatively short
    distance away)
drill surface hole
set surface casing (but ordinarily not the cement
    or cementing therefor)
drill main hole
set intermediate and production casing
provide bits
provide water
provide "day work" (rig and crew time spent in
    certain subsidiary operations or auxiliary
    to other services such as stimulation, coring,
    etc.)
clean up and restore the surface.

Typically a contract is written to provide all the above services, except day work, at a fixed price, and day work at a per diem price. Sometimes "contract costs" include only the fixed price and not the additional per diem work that may be done. In the present analysis contractor costs will include day work. Numerous variations of the above typical scheme occur. For example, sometimes the day work begins at a certain depth, after which bit costs become operator costs also.

The "operator costs" typically include the following:

Mud
casing and tubing
casing accessories
wellhead equipment
cement
cementing services
logging
stimulating
coring
perforating
formation testing
engineering
supervision
overhead.

CONTRACTOR COSTS

Correlations of contractor cost with depth are not readily available. Recourse will, therefore, be had to an earlier study[5] in which drillers' 1956 prices for oil wells, mostly in Texas, were depicted as a function of depth. The drillers' price in this instance included the day work costs. In Figure 1 these data are shown adjusted to estimated 1961 conditions by applying the

Index of Contract Drilling Rates per Foot compiled by the IPAA[4] from surveys made by the American Association of Oil Well Drilling Contractors (AAOWDC). The anticipated index for 1961 was 85. 0 (1947-49 = 100).

As a check on the compatibility of the contract per foot rates with the total well per foot costs there was computed the weighted average percentage that the contract costs are of the total cost (from Figure 1) at nine average depths corresponding to the depth classifications of the Joint Association Surveys. The weighting of each depth classification was by the footage of oil and gas wells drilled in 1959 in that depth classification. This percent should correspond with the total contractor costs as percentage of total well costs under 1961 conditions. Such a figure for comparison is not directly available, but a corresponding figure is available from the 1947-49 average of contract costs per foot and other costs per foot relative to total cost per foot drilled as reported by the American Association of Oil Well Drilling Contractors. The percentages were 54. 3 for operator costs per well and 45. 7 for contractor costs per well.[4] These percentages were corrected to 1960 conditions by applying the IPAA-adjusted index of direct operator costs per well and the index of contractor costs per well.[4] The weighted average percentage from Figure 1 is 30. 8 percent, while the adjusted percentage from the AAOWDC is 25. 8 percent. Upon consideration that the 25. 8 percent does not include day work while the 30. 8 percent does, this is seen to be a reasonable check on the compatibility of the drillers' prices with the Joint Association well costs. As another check on compatibility the weighted average per foot contractor drilling costs were computed from Figure 1 by using the actual footage of oil and gas wells drilled in 1959 in each depth classification. The weighted average price was $4. 91 per foot. The AAOWDC reported[4] the 1960 average price as $4. 11 per foot. The curve of Figure 1 is again shown to be reasonably compatible. Both checks for compatibility showed the curve to be high by approximately 20 percent, but whether this is a significant identity or merely a coincidence has not been explored.

MUD COSTS

The actual volume of mud in use at any one stage of drilling comprises the mud circulating in and filling the hole, plus the mud in a reserve mud pit. For a 6, 000- to 7, 000-foot well the mud pit will contain 300 to 350 barrels, and, for a 12, 000-foot well, 400 to 450 barrels. Some properties of the mud are adjusted by suitable additions of weighting agents and chemicals. Most important among these are density, viscosity, filtration properties, and chemical reaction properties. The most important determinant of mud costs is the density. For example, a 9-pound-per-gallon mud such as used in west Texas will cost about $4 per barrel while a 16-pound mud such as used in southern Louisiana and the Texas Gulf Coast costs about $9.50 per barrel. Some of the mud is lost by penetration into the formation. An extreme form of this, called lost circulation, occurs when major crevices are encountered. But mud may also be lost occasionally by blowouts. The major cost of mud is frequently not the initial cost but the daily maintenance cost for chemicals and other additives to change the nature of the mud as the drilling progresses and different formations are encountered. All these indeterminant factors make it very difficult to arrive at a theoretical mud cost. Nevertheless, mud costs are appreciable and must be included for our purposes. Reference 6, from which all the data in this section are taken, indicates that the national average mud cost for the first 6 months of 1961 was $4,300 per well mudded. Not all wells, however, use commercial mud.

Information was made available to us [6] on actual or anticipated mud costs for about 530 wells drilled in the south Texas area between February and October 1961 for which mud was supplied by the half dozen mud companies operating in the area. These data are shown in Figure 3, where it is seen that at any depth there is a wide variation in mud costs amounting to a five- to tenfold range depending on depth. A trend line approximating the median in each cell is, however, shown, and was used in the estimates.

CASING AND TUBING COSTS

References 5, 7, and 8 provide data on the cost of seamless steel casing and tubing. The data for Pennsylvania in Reference 7 have been increased by the carload (70,000 lb) freight rate from Pittsburgh to San Antonio to provide prices delivered to a common point. The data were then corrected to a Bureau of Labor Statistics wholesale price index [9] (for oil well casing Code No. 1014-59) of 190 corresponding to mid-1961. This correlation as used in the computations is shown in Figure 4.

PLASTIC LINING COSTS

Tubing and casing may be purchased plastic lined as a corrosion-proofing measure, or unlined pipe may be custom lined. By either method the cost will be practically identical. A supplier's price list [10] was used to correlate plastic lining in

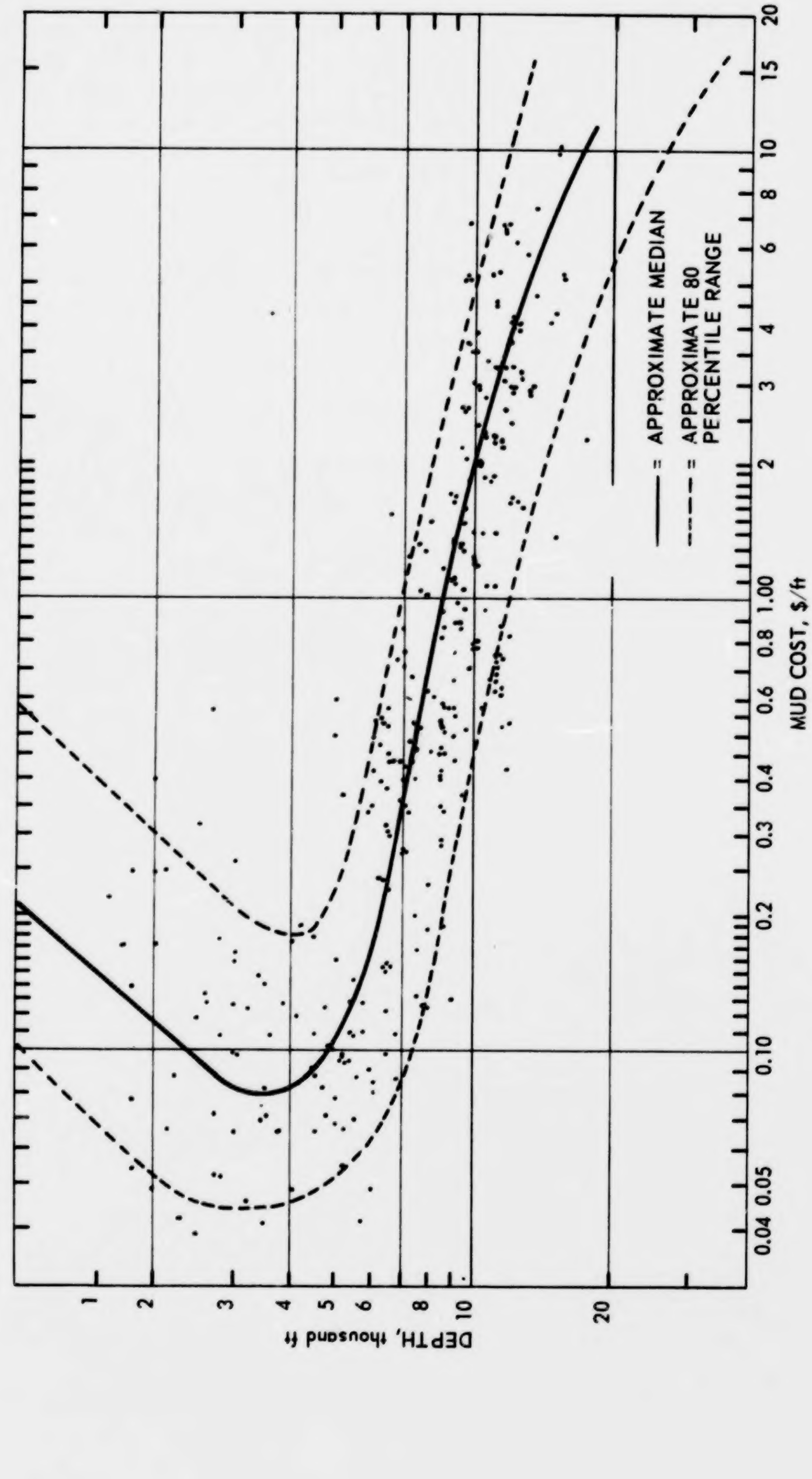

Figure 3. Trend of mud costs (approximately 530 wells, South Texas, Feb. - Oct. 1961).

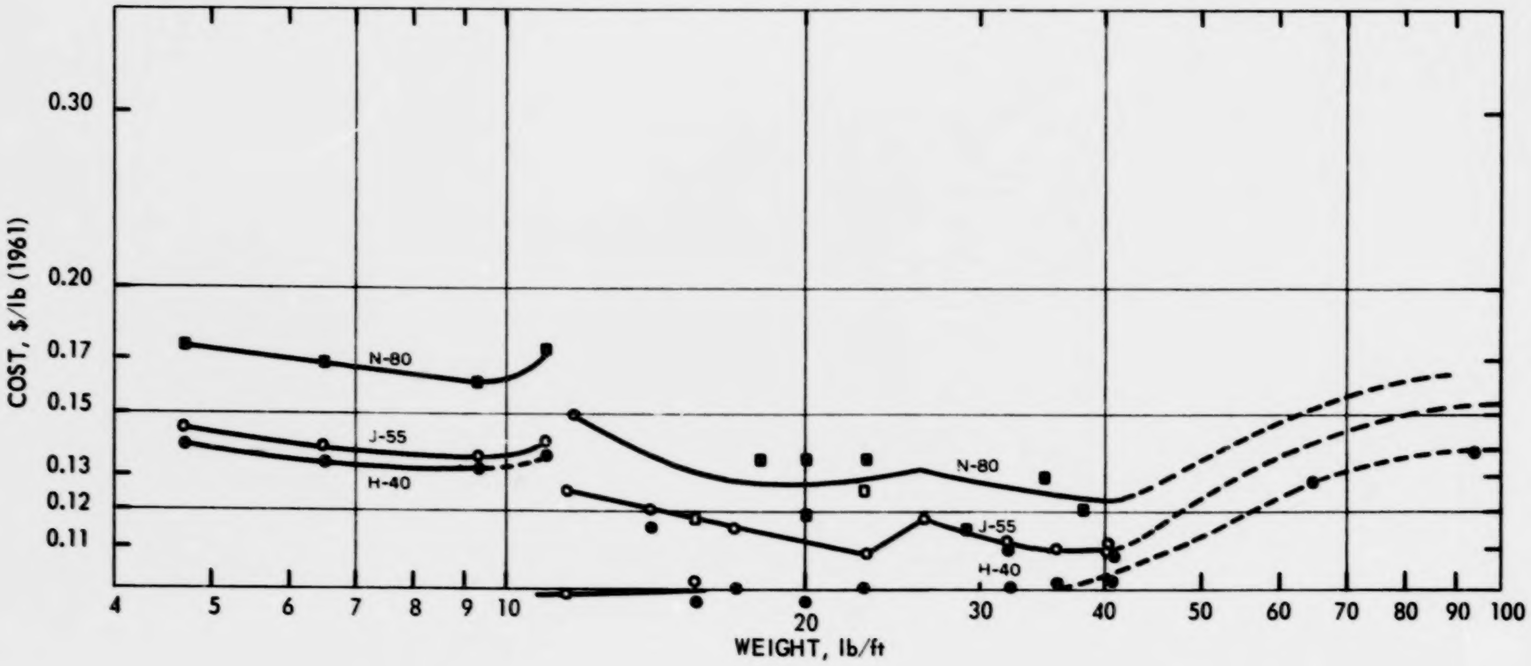

Figure 4. Cost of API standard tubing and casing, Gulf Coast 1961.

terms of dollars per foot inch as a function of outside diameter, and the corresponding dollars per foot values were used in the computations. Selected values given for illustration are as follows:

OD pipe, in.	2	4	6	8-5/8	12-3/4	over 12-3/4
$/ft in.	0.17	0.187	0.182	0.186	0.196	0.20 (estimate)

CASING ACCESSORIES COSTS

Certain accessory items are incidental to setting the casing and cementing.[11] Wall cleaners are used to remove the mud from the hole face prior to cementing. Either the rotating or the reciprocating type may be used. The rotating type comes in 5-foot sections and they are used opposite the producing formation with one or two sections above and below this. A casing swivel is rented to utilize them. Centralizers keep the casing in the center of the hole. Typically one centralizer is used at each of the bottom two or three collars, and a few centralizers, on the casing of the hole. Usually a 2,500-foot well would use three to four, and a 6,000-foot would use eight. Float shoes are used to guide the casing through the hole and to prevent backflow of mud into the casing, which allows it to be floated while setting. Typically one float shoe is used in depths up to 4,000 feet. Beyond this an additional float collar is used on the joint below the bottom as a precaution. The prices of casing accessories are available from service company catalogs.[12]

Actual costs for casing accessories according to the above schedule have been computed as shown in Table 1.

Table 1. COST OF CASING ACCESSORIES, $

Depth, thousand ft	OD, in.		
	4½	7	10-¾
3	390	435	525
6	–	495	–
12	625	655	815

These costs were plotted against casing diameter (not shown) and rough interpolations were made for different diameters and different depths.

WELLHEAD EQUIPMENT COSTS

Wellhead equipment costs include the valving, blowout preventers, wellhead, and adapter constituting the "Christmas tree" at the wellhead.[13] For the injection wells here planned the equipment will be relatively simple, consisting of only wellhead, adapter, and valve.[14] Costs of the wellhead and adapter have been interpolated from quotations[14] as follows:

OD, in.	2-1/2	3	4	6	8	10	12	14	18
$	350	350	350	370	440	510	575	640	740

Costs of valves vary with the operating pressure and were approximated by adjusting the costs of steel gate valves from Reference 15, Figure 291, to the July 1961 Wholesale Price Index for cast steel valves (Code 1149-04).

The data were used in the form of a graph (not shown). For a 7-inch casing and 300 psi operating pressure the wellhead equipment, above, costs approximately $1,250. The wellhead and adapter may conveniently be segregated from the valve costs since the latter are the only components of well costs that vary with pressure. Accordingly they were treated with the injection pump pumping equipment, which also varies in cost with pressure.

CEMENT COSTS

The per sack cement costs are as follows:

50-50 Cement-Pozmix	- $0.93	national average price[16]
Handling charge	- 0.35	
Hauling charge	- 0.59	(0.12/ton mile)
Total	$1.87/sack	

The average haul was estimated at 100 miles in accordance with the procedure used in Reference 5. Reference 17 gives the figures for the number of sacks of cement per linear foot for various combinations of casing and hole.

CEMENTING COSTS

The price of cementing services (placement of the cement) is composed of a charge for the pumping truck dependent upon depth, and for excess mileage. A different flat rate applies for the second stage of multiple-stage cementing jobs.[18] In addition it is customary to precede a cementing job with a chemical wash to insure a firmer bond and remove the drilling mud. The price is based on a per gallon figure when run in conjunction with cementing.

Typical practice in cementing would involve one job in cementing the surface casing and a second job in cementing the production string. If the production string were a single string deeper than 6,000 feet it is likely that double-stage cementing would be used. For example, if the well were 12,000 feet deep, cementing from 12,000 back to 6,000 feet would be done in the first stage and from 6,000 to the surface in the second stage. For computation then it is assumed that the cementing job will consist of the surface-casing job plus single-stage cementing to 6,000 feet or double-stage cementing below 6,000 feet. Each cementing job would be preceded with a 500-gallon chemical-wash treatment. Mileage will be taken on the 65 miles' average haul beyond the 35-mile free radius. Cementing for the 1,000-foot well will consist of cementing production casing only, surface casing being omitted. Above 12,000 feet a three-string casing would be used.

Under these assumptions the following is the cost of the cementing service.

Thousand ft	1	2	3	4	5	6	8	10	12	14 (3-string)	15
$	564	1,456	1,456	1,456	1,471	1,498	2,020	2,162	2,383	3,200	3,454

ELECTRIC LOGGING COSTS

Standard procedure for electric logging would call for a self-potential log and three or four resistivity logs. The costs of this[19] involve a $150 service charge, plus a 5 cents per foot depth charge, plus a 6 cents per foot logging charge. It will be assumed that 500 feet of formation is logged at each logging. Furthermore, as is the typical practice, it is assumed that one log would be run up to the 6,000-foot depth; the 6,000-foot log plus a second log at depths up to 12,000 feet; and the 6,000- and 12,000-foot logs plus an additional log at depths up to 15,000 feet. Computed on this basis the costs would be as follows:

Depth, thousand ft	1	2	3	4	6	7	8	10	12	13	14	15
$	230	280	330	380	480	1,110	1,160	1,260	1,360	2,190	2,250	2,290

PERFORATING COSTS

It is unlikely that casing to the bottom with perforations would be practiced for injection wells. An open-hole completion would be more logical except where the formations are incompetent and tend to cave into the hole. It would ordinarily be thought that at depths suitable for injection competent formations would be the rule. Accordingly perforating is not included as a cost in the computations, but, to show the magnitude of this cost in case it should be called for, the following is offered.[19]

Perforation charges (here given for a retrievable jet gun) consist of a flat service charge, a charge for 1 to 20 holes varying with depth, and a charge per hole for additional holes beyond 20. Costs for bullet guns or expendable guns are only slightly different from these. Perforating is usually accompanied by a depth control and collar log for which the charge is 3 cents per foot depth charged and 5 cents per foot logging charge, $85 minimum. Mileage charges are 50 cents per mile beyond a 150-mile free radius. It will be assumed that perforation would be done at four holes per foot with 100 feet of injection formation perforated, and that 200 feet would be logged in the depth control log. Under these conditions the costs per foot for perforating and depth control logging is as follows:

Depth, thousand ft	1	2	3	4	5	6	8	10	12	14	15
$	825	848	894	955	1,016	1,082	1,244	1,454	1,674	1,914	2,035

INJECTIVITY PROFILE COSTS

It will be desirable to run an injectivity profile of the well to determine the areas of the face that will take the most water. The cost for water wells is about $500.[5] Again, however, it would appear that costs would be higher for wells of extreme depth. Accordingly it will be assumed that injectivity profiles will cost the same as electric logging, namely $150 service charge, 5 cents per foot depth charge, and 6 cents per foot logging charge, with a minimum of $500. It is assumed that at least two injectivity profiles will be run, one before and one after stimulation. On this basis the costs for injectivity profile will be as follows:

Depth, thousand ft	1	5	6	8	10	12	14	16
$	1,000	1,000	1,020	1,220	1,420	1,620	1,820	2,020

STIMULATING COSTS

It is common practice to stimulate oil and injection wells by any of a number of methods, the most prominent of which are pressure acidizing and hydraulic fracturing. Stimulation means the removal of an underground resistance to flow, which increases the capability of the well. Acidizing costs are based on the use of a pumper truck plus the cost of the acid, neither of which depends upon depth or diameter. Fracturing costs are based on the pumping truck plus the cost of the special sand and fracturing fluid used, and again, neither depends upon depth or diameter. The determinants of the size and thus the cost of pressure acidizing or hydraulic fracturing treatments are the permeability of the formation, its thickness, and the depth to which treatment is desired. It is possible to compute the economic fracturing size from some of these parameters, that is, the size of treatment that will return the greatest money benefit per dollar of treatment cost. This is somewhat less readily done for acidizing.

In any event the variations in the parameters are such that generalizations cannot be made. Reference 20 reports a study of the distribution of stimulation treatment costs for water wells and injection wells. There it is shown that the median cost of a pressure acidizing treatment was $950 in 1959 and, of a fracturing treatment, $1,250. For the present computations it will be assumed that the stimulation at the time of completion costs the average of these or $1,100 for a relatively shallow well.

It seems unlikely, however, that such costs would apply to very deep wells. A 10,000-gallon acid treatment, for example, is not unheard of and would cost over $4,000. It is unlikely that, after the expenditure had been made in a 12,000-foot well, an $1,100 acidizing job would be done when better performance could be expected by the expenditure of an additional $3,000, which would be small compared to the total cost of the well. Accordingly it will be assumed that stimulation costs will vary with depth as follows:

Depth, thousand ft	1	4	5	6	8	10	12	14	16
$	1,100	1,100	1,500	1,900	2,600	3,300	4,000	4,800	5,700

SUPERVISION COSTS

Even though most of the work of constructing a well may be performed by the drilling contractor and by other service contractors, some supervision and technical management must be supplied by the owner (i. e., operator). Data on such costs are not available, but it will be assumed that the supervision is exercised by a manager-geologist who will spend one-half of his 8-hour-per-day time plus 2 days at these duties during the actual construction time. A salary of $10,000 per year and overhead costs on that of 100 percent will be assumed for a daily cost of $80.

The number of days spent in constructing a well may vary greatly with the subsurface conditions, the weather, and other indeterminate factors. Even the actual penetration rate (i. e., the feet of hole drilled divided by the number of hours' rotating with the bit on the bottom) may vary greatly depending on formation properties and other indeterminate factors. A study of more than 500 drilling operations[21] led to the conclusion that personnel and equipment efficiency were more important than any other factors in influencing the rate of penetration and drilling. There is, however, a decided decrease in the average penetration rate as well depth increases. Assumed penetration rates at various depths have been chosen as typical, from references too numerous to mention and are given in Table 2.

Table 2. ASSUMED PENETRATION RATES AT VARIOUS DEPTHS

Depth	Assumed penetration rate, ft/rotating hour	Rig days	Supervision cost, $
1	60	4	320
2	60	5	360
3	60	6	400
4	60	8	480
5	58	9	520
6	50	12	640
8	25	30	1,360
10	10	91	3,840
12	8	133	5,120
14	6	204	8,300
16	5	276	11,200

The percent of time actually rotating also varies considerably but much less than penetration rate. Quoted at random are: Gulf Coast 43.7 percent;[22] west Texas, 1947, 48.2 percent;[23] and California 42 percent.[21] For the present study it will be assumed that rotating time is 50 percent of total rig time.

The above assumptions lead to a number of rig days and a supervision cost for each depth according to the Table. In unusual cases, for example, an unusually large-diameter deep well, supervision cost has been doubled in the present computations.

CONTINGENCY COSTS

A contingency of 10 percent of the subtotal of other costs, except general and administrative, was provided for. In unusual or untried conditions, for example, extreme-diameter deep wells, the contingency was increased to 20 percent.

GENERAL, ADMINISTRATIVE, AND ENGINEERING COSTS

Any construction program involves a general and administrative expense, which here will be considered to include engineering and purchasing. Engineering expenses, that is, for design and supervision of construction, are typically 7 percent of total cost, but in the present study construction supervision has been separately accounted for. Purchasing of diversified items typically costs 7 percent of purchases, which here would apply only on the materials used such as casing, casing accessories, wellhead equipment, and similar tangible items. By taking appropriate portions of these and adding a small amount for general and administrative expense, it will be assumed that the total will be 10 percent of the direct expenditures.

Synthesis Of Well Component Costs

As a check on the adequacy of the cost estimation data developed above, they will be used to compute the synthetic costs of oil and gas wells of various depths for comparison with the average U.S. costs at each depth.

EXEMPLARY COMPUTATION (7,000-ft WELL, 7-in CASING)

1. Contractor: Read from Figure 1			
$5.20/ft average x 7,000 ft		$ 36,300	
6.00 maximum			$42,000
4.10 minimum			28,600
2. Mud: Read from Figure 3			
$0.36/ft average x 7,000 ft		2,520	
0.90 maximum			6,300
0.10 minimum			730
3. Casing:			
1,000 ft 10-3/4 in. 45.50 (lb per ft) J55, read from Figure 4 $0.116/lb	$5,260		
3,400 ft 7 in. 20.00 J55 0.112	7,630		
3,200 ft 7 in. 23.00 N80 0.128	9,420		
400 ft 7 in. 26.00 N80 0.132	1,370		

4.	Plastic lining: Read from page 14 7 in., $1.35/ft x 7,000 ft	9,450		
5.	Casing accessories: Read from graph (not shown) see page 14 1,000 ft surface casing 10-3/4 in.	480		
	7,000 ft production casing 7 in.	550		
	Sum of casing items 3, 4, 5		34,160	
6.	Cement 1,000 ft 10-3/4 x 13-3/4 in. (hole) Read from[17] 0.3644 sacks/ft x 1,000 x $1.87/sack	680		
	1,000 ft 7 in. x 10-3/4 in. 0.2583 x 1,000 x 1.87	500		
	6,000 ft 7 in. x 9 in. (hole) 0.1587 x 6,000 x 1.87	1,790		
7.	Cementing 7,000 ft, page 16	1,750		
	Sum of cement items 6, 7		4,720	
8.	Logging, page 16, $0.159 x 7,000 ft	1,110		
9.	Wellhead equipment (incl valve) page 15	1,250		
10.	Stimulation, page 18	2,250		
11.	Injectivity profile, page 17	1,120		
	Sum of other items, 8, 9, 10, 11		5,730	
12.	Supervision, page 19		1,000	
13.	Subtotal of items 1 to 12		84,430	
14.	Contingency, 10 percent of 13		8,443	
15.	G and A, 10 percent of 13		8,443	
	TOTAL (incl valve)		$101,316	
	$/ft average		14.46	
	$/ft maximum			$16.14
	$/ft minimum			12.82
	Read from U.S. curve, Figure 1		15.50	
	Read from Texas Gulf, Figure 1		15.30	

SELECTION OF CASING PROGRAM

The casing programs used in the checking computations are for conventional two-string programs after Reference 24. This provides for a double-string program, 10-3/4-inch surface casing and a 7-inch production string. In the present study 1,000 feet of surface casing was taken except for the 1,000-foot well, which is constructed without surface casing.

It is likely that below 12,000 feet a double-string program would not suffice. Accordingly a triple-string program was used in the present computation comprising 2,000 feet of 13-3/8-inch surface casing, approximately half depth with 9-5/8-inch protection or intermediate string and full depth with 7-inch production string. Cementing is to the surface in all instances.

SUMMARY OF CHECKING COMPUTATIONS

The type of computation exemplified in the preceding section was made for wells at four depths with results as given in Table 3.

Table 3. SYNTHETIC COSTS OF WELLS

	Depth, thousand ft				
Comparison	3	7	12	15	Average of 4
Computed, $/ft avg	11.40	14.46	22.70	34.40	
Read Figure 1 U.S.	10.80	15.50	26	39	
Deviation, %	+5.6	-7.2	-12.7	-11.8	±9.5
Maximum, $/ft	12.10	16.14	34.80	46.70	
Minimum, $/ft	11.25	12.82	19.60	29.10	
Breakdown, %					
Contractor	22.8	36.0	39.0	31.7	
Mud	0.7	2.5	13.3	17.4	
Casing	38.4	33.4	25.6	27.6	
Cement	9.5	4.7	2.5	2.7	
Supervision	1.1	1.0	0.6	1.9	
Contingency	8.3	8.3	8.3	8.3	
G & A	8.3	8.3	8.3	8.3	
Other	10.9	5.8	2.4	2.1	
	100	100	100	100	

The comparison plotted in Figure 5 shows that the synthesis of the component costs comes reasonably close to estimating average U.S. well costs over the entire range of depth. It may

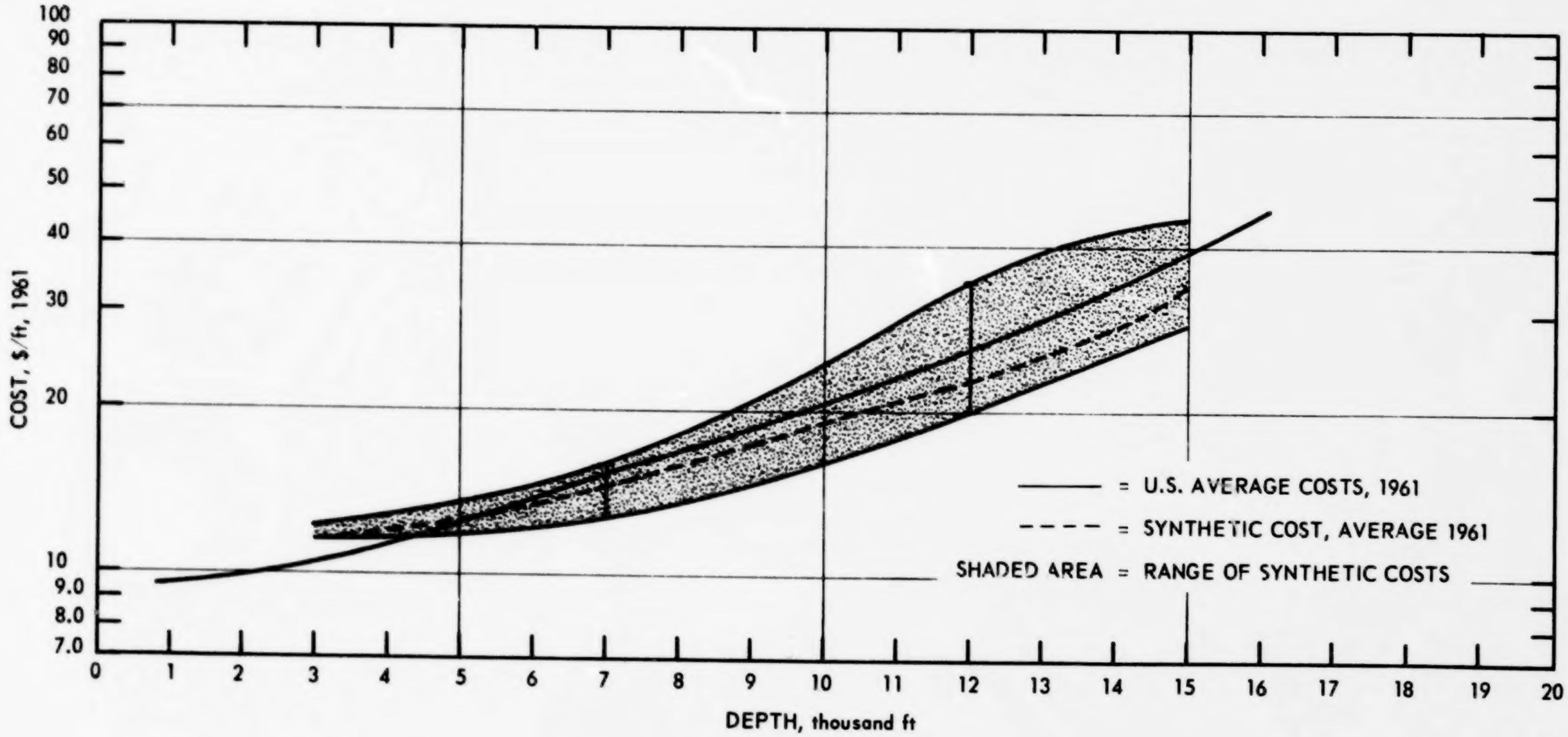

Figure 5. Synthetic well costs.

be concluded that application of the estimated components will reproduce average U. S. well costs at any depth with a deviation of less than 12 percent. The extreme range in data, owing to variability in contractor costs and mud costs, follows the experienced U. S. curve and brackets it at every depth above 4, 000 feet.

The breakdown shows the relative importance of groups of cost components at each depth. Major items at all depths are contractor costs and casing items, with mud costs becoming important at the greater depths.

Effect Of Diameter On Well Construction Costs

DIAMETER OF THE STATISTICAL WELL

Our objective involves computing typical costs for injection wells of various diameters over a range much greater than customarily used in oil well practice. For all cost components except contractor costs and mud costs, the variation of the component cost with diameter is contained in the data themselves. In succeeding sections indexes will be developed by which contractor costs and mud costs can be roughly related to hole diameter. First, however, it is necessary to know what standard diameter to choose as the base, to which presumably the statistical data available on well costs, drilling costs, and mud costs apply.

Statistical data are not available on distribution of U. S. wells by diameter, but an approximation is made as follows. Reference 25 lists the most popular casing and bit programs for rotary drilling in various oil-producing areas. Within each area the sizes are shown by order of importance as indicated by bit sales records. Of 98 listings of typical programs in the United States for the bit used in drilling for the production string, the average diameter is 8-1/2, the median, 8-3/4, and the mode, 8-3/4 inches. Since the date of this listing corresponds with the date of the contractor cost study, [5] it may be assumed that the size hole that best represents the contractor's cost study is 8-3/4 inches.

The actual weighted-average hole size would, however, be larger than this since larger diameter surface, protection, and intermediate strings are used above the production string. The commonest hole size above 8-3/4 inches is 12-1/4 inches. If the surface hole is one-sixth as deep as the well, the weighted-average diameter is 9-3/8 inches. If, as is more typical, the surface hole is one-twelfth the depth of the well, the weighted-average size is 9.0 inches. Since 9-3/8 inches is not a standard bit size, it will be assumed that the weighted-average hole diameter corresponding to the contractor's cost and mud cost is 9 inches.

INFLUENCE OF HOLE DIAMETER ON CONTRACTOR COSTS

The variation of contractor costs (i.e., the cost of creating the hole) with hole diameter is quite obscure in oil field practice. In water well construction the diameter of the hole is a strong determinant of the drilling cost. The cost per foot is roughly proportional to the hole diameter up to about 8 inches and thereafter increases even more rapidly than hole diameter.[26]

In oil field practice, however, the hole diameter does not enter as a determinant in considering well costs. For example, in the four national statistical surveys made by the Joint Associations[1, 2, 3] the influence of depth is recognized strongly, but no mention is made of the influence of diameter. The modern trend is, however, to smaller size hole and casing to reduce overall costs. Several years ago "slim-hole" drilling seemed to offer promise of a general reduction in costs, but insofar as hole size itself is concerned, it has been found that extremely small holes, for example, 4-3/4 inches, are no less costly than intermediate size holes, for example, 6-3/4 inches. A recent AAOWDC survey[13] shows that despite earlier 4-3/4- to 3-7/8-inch holes, present practice centers on 6-3/4-inch holes. Eighty percent of the companies surveyed thought that 6-1/8 to 6-3/4 inches was the best range for a "slim hole." In the smaller size, bit wear is greater, which requires an increased number of trips in and out of the hole to change bits. Also, with larger size holes, it is possible to weight the drill pipe with collars to increase the weight on the bit and achieve greater penetration rate. Such published information as is available on the variation of drilling cost with hole diameter is usually presented in connection with economic studies of slim-hole programs.[13, 21, 27 to 30] Data from these references were plotted as contractor costs, dollars per foot inch, against hole size on log-log paper and interpolations or extrapolations were made to allow comparison of the cost per foot inch with those at a hypothetical 9-inch hole taken as 100. The essential parts of the data together with the index numbers arrived at are contained in Table 4.

It is seen for the most part that such studies have been made to develop contractor costs (usually as a part of total costs from which it has been here extracted) for the "next smaller" size,

Table 4. RELATIVE CONTRACTOR COST FOR DRILLING AS A FUNCTION OF HOLE DIAMETER, $/ft in.

Region	Year	Approx. depth, ft	No. of wells	Diam range, inches	Index No.										
					4 in.	5 in.	6 in.	7 in.	9 in.	10 in.	12 in.	15 in.	20 in.	36 in.	Reference
Miss.	1960	7,000	3	5-5/8 to 7-7/8		154	127	114	100						27
"	"	9,500	3	5-5/8 to 8-3/4		149	127	114	100						27
"	"	9,200	3	" "		141	116	107	100						27
Midcontinent	1961	700-1,800	a	12-1/4 to 17-1/2		—	—	—	100		96	93			29
"	"	4,700	8	5-5/8 to 7-7/8		95	—	97	100		—	—			29
South Texas	"	8,400	b	9-7/8 to 12-1/4		—	—	—	100	108	127	199			30
Texas Gulf Coast	"	6,800	3	6-7/8 to 7-7/8		—	152	131	100	—					13
" " "	1936-1941	5,000-8,000	84	8-5/8 to 9-7/8		—	—	89	100	105					28
Water wells:															
North Central	1959	100-1,500	c	4 to 36	82	100	97	99	100	100	105	111	124	132	20
West	"	" "	c	" "	85	88	90	91	100	107	130	148	148	130	20

a. Estimate.

b. Approximate quotation.

c. Survey of many drillers.

which historically is about as accurate a definition as can be given for slim-hole drilling. For this reason the ranges covered by the individual comparisons are small when measured against our present purposes.

A plot of these cost indexes is shown in Figure 6, which brings out the variant and indeed contradictory nature of the data. Above the 9-inch face the 54 wells studied, the south Texas driller's quotation and the Water Well West curves seem to agree. We shall assume figures roughly the average of these three curves. Below 9 inches the divergence is greater. Since the Texas Gulf Coast data are based on but two wells, the best probability is the Mississippi data covering nine wells, which lie between the other two.

For computation purposes then indexes as shown in Table 5 have been chosen according to the common bit sizes. Note that an index has been computed for dollars per foot also.

Table 5. CHOSEN VALUES FOR RELATIVE CONTRACTOR COST OF DRILLING (9 in. = 100)

Common bit size, in.	6-3/4	7-3/8	7-5/8	7-3/4	7-7/8	8-1/2	8-5/8	8-3/4	9
Index, $/ft in.	118	113	110	109	108	104	103	102	100
Index, $/ft	88.5	91.5	93.1	93.9	94.5	98.5	98.8	99.3	100

Common bit size, in.	9-5/8	9-7/8	10-5/8	11	12	12-1/4	13-3/4	15	17-1/2
Index, $/ft in.	105	107	111	117	129	132	148	(150)	(150)
Index, $/ft	112.3	117.5	131	143	172	180	226	(250)	(292)

THEORETICAL VARIATION OF MUD COST WITH DIAMETER

As shown previously the variation in actual mud costs at a given depth is large, but there is a trend with depth. The variation is so great that any estimate of variations with diameter must of necessity refer to a strictly hypothetical, ideal case.

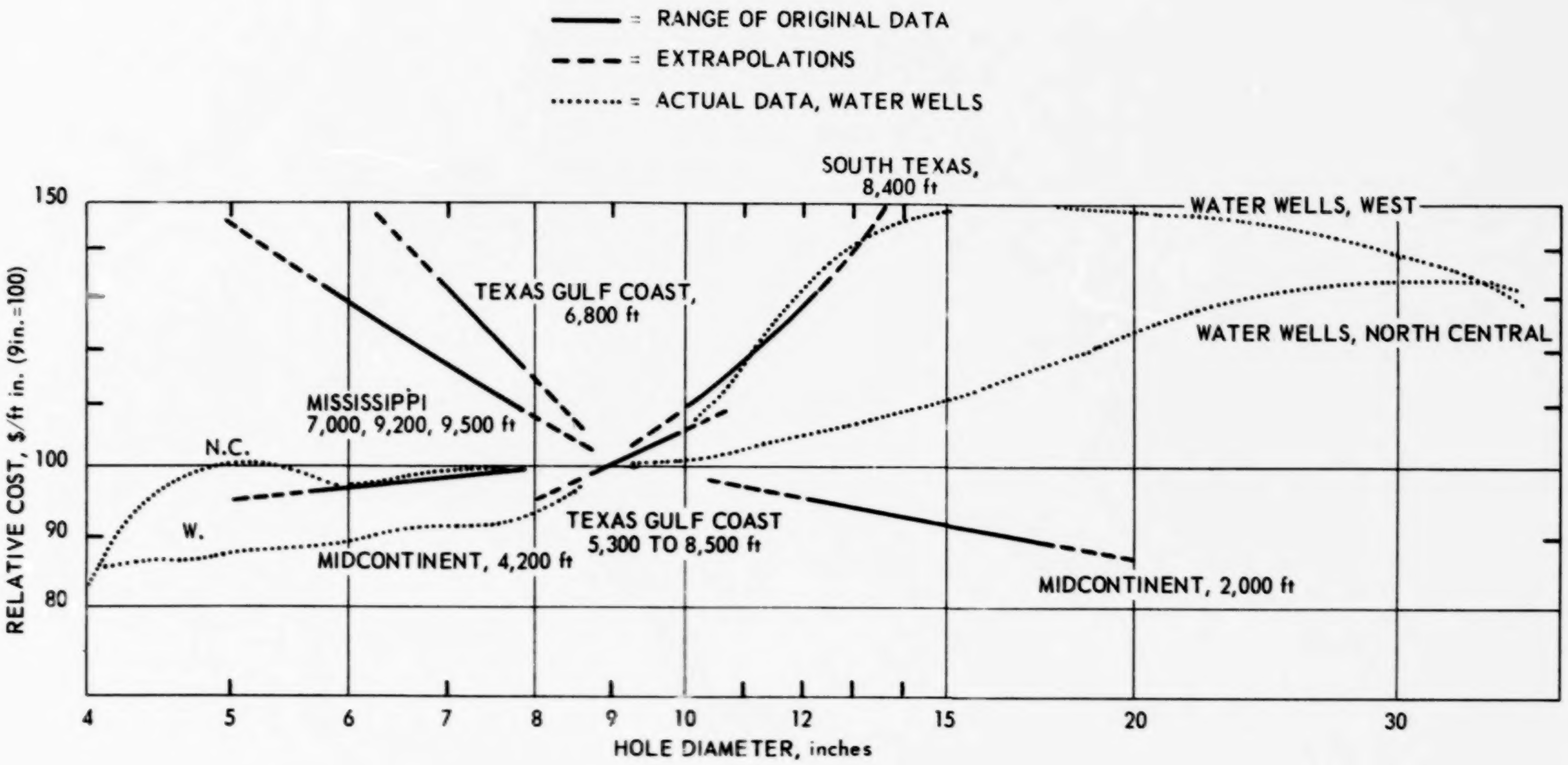

Figure 6. Relative contractor cost for drilling.

It will be assumed that the actual mud cost will be proportional to the mud in the hole and in the pits at the time total depth is reached. Obviously the number of lost-circulation incidents or blowouts bears no relation to the diameter of the hole, and in any given pair of cases, as may be seen in Figure 3, the mud cost for the smaller diameter might be greater than that for the larger diameter depending in part on these accidental circumstances.

Computations were made of the amount of mud in the hole at depth plus that in the mud pits for a number of standard holes as shown in Table 6.

Table 6. HOLE SIZES USED IN COMPUTATIONS

Surface hole (1000 ft), in.	9-3/8	12-1/4	15	20
Main hole (remainder), in.	6-3/4	8-3/4	10-5/8	13-3/4
Index number	75	100	130	196
Avg deviation, %	3.6	--	2.0	3.5

It was assumed that the surface hole would be 1,000 feet deep and that the mud pits contained 300 barrels for a 3,000-foot hole, up to 500 barrels for a 15,000-foot, and slightly more for an extreme-diameter hole. For the 6-3/4-inch hole computations were made at five depths between 4,000 and 15,000 feet. The variation in index number with depth was only a few percent. Accordingly for the other sample holes computations were made at only three depths.

The computed values were plotted on log-log paper and the following indexes were chosen from the curve:

Mud cost indexes (8-3/4 in. = 100)

Main hole diam., in.	6-3/4	7-5/8	8-5/8	8-3/4	8-5/8	10-5/8	12-1/4	15	17-1/2	18-3/4
Index, $/ft	79	86	98	100	114	131	160	223	300	338

EXEMPLARY COMPUTATION: WELL COSTS, NONSTANDARD DIAMETERS

The following computation for a 7,000-foot well with 10-3/4-inch production casing is provided to show the method of computing synthetic well costs at diameters other than standard.

1.	Contractor cost for standard well, $36,300		
	Read diameter index, 13-3/4 in. hole		
	from page 10: 2.26 x 36,300		$ 82,000
2.	Mud cost. Read from page 11:		
	1.96 x $2,520 standard		4,940
3.	Casing		
	1,000 ft 16 in. H-40 65.00. Read from Figure 4.	0.128/lb	8,320
	3,400 ft 10-3/4 in. J-55 45.50	0.116	17,900
	3,200 ft " N-80 51.00	0.125	20,400
	400 ft " " 55.50	0.132	2,930
4.	Lining. Read from page 14. $2.00 x 7,000		14,000
5.	Casing accessories. Read from graph (not shown)		
	see page 14, 1,000 ft 16 in. surface		650
	7,000 ft 10-3/4 in. production		660
6.	Cement		
	1,000 ft 16 x 20 (hole). Read from[18] 0.7140 sacks/ft		
	1,000 ft x 0.7140 x $1.87		1,330
	1,000 ft 16 x 10-3/4 1,000 x 0.5801 x $1.87		1,080
	6,000 ft 13-3/4 (hole) x 10-3/4 6,000 x 0.3644 x $1.87		4,100
7.	Cementing, 7,000 ft, page 16		1,750
8.	Logging, page 16		1,110
9.	Wellhead equipment, 10-3/4 in. (except valve), page 15		580
10.	Stimulation, page 18		2,250
11.	Injectivity profile, page 17		1,120
12.	Supervision, page 19		1,000
13.	Subtotal		$166,120
14.	Contingency, 10 percent		16,612
15.	G and A, 10 percent		16,612
	Cost of well (except valve)		$199.344

Cost Of Pumping Equipment And Operation

COST OF ELECTRIC MOTORS

Chilton[31] gives a cost correlation for electric motors installed at an Engineering News-Record Construction Cost

Index of 400, which existed in May 1947. These may be corrected to 1961 by application of the Marshall and Stevens Electric Power Equipment Cost Index (1926 = 100), which stood at 150 in 1947 and an estimated 224 in mid-1961.

Adams[31] gives more recent costs for electric motors not including foundations as of September 1959. Lundeen and Clark[31] provide data on costs of foundations for centrifugal pumps and motors. The amount is small compared with the cost of the motor, and one-half of the Lundeen and Clark cost for foundation is taken as applicable to the Adams motors. The sum of motor and foundation was corrected to mid-1961 by the ratio of the Wholesale Price Index[9] for motors and generators (Code 1173), which stood at 186.4 in 1959 and at 177.1 in mid-1961.

When plotted (not shown) on log-log paper as dollars per horsepower against motor horsepower, the Adams (1959) dollars per horsepower corrected to 1961 lies about 20 percent above the Chilton data. Being more recent, the Adams data are used in the present study, while the Chilton data are used to guide extrapolation beyond the extremes of the Adams data.

Correlated costs thus arrived at are as follows:

Cost of electric motors installed
Motor (1,800 rpm enclosed 220 to 440 V)
Control
Conduit
Wire
Foundation
Installation labor

Motor, HP	1	3	10	20	50	100	200
$/HP, 1961	700	290	125	75	52	44	42

COST OF CENTRIFUGAL PUMPS

Chilton[31] correlates cost of centrifugal pump with driver installed according to driver horsepower at an Engineering News-Record Construction Cost Index of 400. By subtracting from these figures the cost of motors (installed) from the same reference, one arrives at the costs of motor and pump installed separately. These were adjusted to mid-1961 by the ratio of the Wholesale Price Indexes[9] (Code 1141 for pumps and Code 1172 for motors) by the ratios 229/117 for pumps and 224/150 for motors. The 1961 installed costs for pumps and motors separately were then summed to provide 1961 costs as follows:

1961 installed costs driver HP	Centrifugal pumps and drivers installed, $/HP (1961)
1	1,267
10	240
100	64
200	50
500	45
1,000	33

COST OF TRIPLEX PUMPS

Earlier data are available and were correlated for the cost of high-pressure pumps. Recently however, Triplex pumps have become available particularly designed for oil field service[32] at considerable reductions in cost.[33] Approximate quotations are $1,800 for the 50 horsepower pump and $6,000 for the 125 horsepower. Foundation and installation costs for the pump only were taken as one-half the costs for pump and motor cited by Lundeen.[31] This brings the cost of the 125 horsepower Triplex pump installed to $6,145 and of the 50 horsepower to $1,930.

To these prices may be added those of electric motors installed, developed above, to arrive at the complete pumping installation shown in Figure 7. Also shown in this Figure is the cost of centrifugal pumps developed in the previous section.

It is seen that the cost of the 50 horsepower Triplex approaches that of the centrifugal pump in the medium horsepower ranges. Note that in certain horsepower ranges it is cheaper to use multiple units of 50 horsepower pumps than to use 125 horsepower pumps. This has been computed on the basis that motors are available in a continuous series of horsepowers, while pumps are available only in the two (maximum) horsepowers indicated.

In the present study the Triplex pumps will be used for wellhead pressures above 400 psi, the centrifugal pumps for the lower pressures. Cost of centrifugal pumps smaller than 1 Driver horsepower will be taken at a flat $1,270, of Triplex at $2,600. In a few of the extreme-pressure cases the computed Triplex pump costs used here are too low for the pressures and somewhat beyond the maxima for the Triplex models quoted.

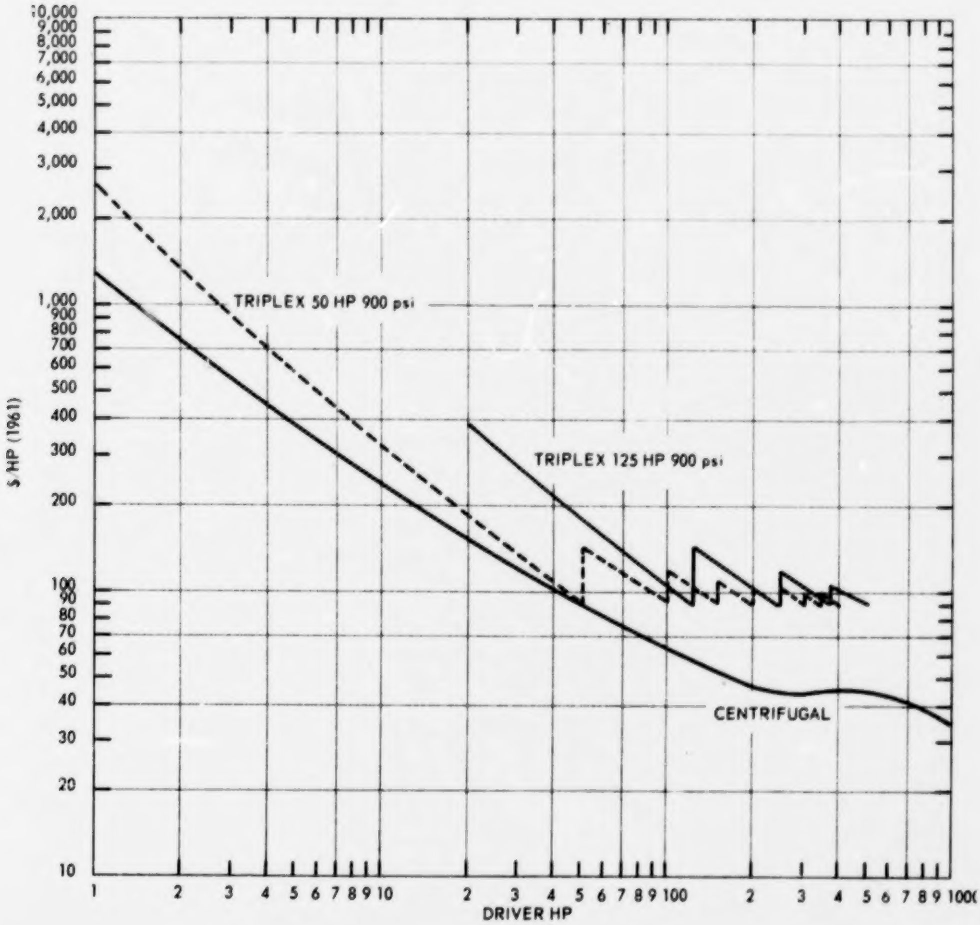

Figure 7. Cost of pumping equipment (pump, motor, accessories, installed and wired, 1961)

FIXED COST OF PUMP OPERATION

The fixed charges on the capital cost of the pumping equipment and appurtenances (as well as on wells and other equipment) will be computed as a 20-year amortization, 4 percent interest on the depreciated investment, 1 percent taxes, 1 percent insurance. On this basis the daily fixed charges are:

$$\text{Capital} \times \frac{0.258}{1{,}000} = \text{daily fixed cost} \qquad (1)$$

COST OF ENERGY FOR PUMPING

Cost of energy for pumping will be computed at 0.5 cent per kilowatt-hour* for electrical energy at the wire, and 84 percent wire-to-water efficiency, load factor of 100 percent and 24-hour-per-day operation. This gives \$0.1068 per water-horsepower-day as the energy cost.

OPERATING, LABOR, AND MAINTENANCE

In Reference 5 an attempt was made to separate out operating and maintenance labor between the conditioning plant and the wells and pumps, as applied to data then available. The separation was, however, inaccurate, for it has since been learned[34] that, in a conditioning plant, well, and pump combination, most of the operating and maintenance labor is applied to the treatment plant. It is quite difficult to obtain uniform experience figures on operating labor, maintenance labor, and repairs. In some cases, "operation" includes maintenance and repairs. In other cases "maintenance" appears as a part of operation, and in others as a synonym for repairs. Stevenson[35] cites 2 man-hours per day for a 500 horsepower electric motor for operating costs. At the average hourly earnings of non-supervisory personnel in oil field work of \$3 per hour corresponding to 1961, and at 84 percent wire-to-water efficiency, this comes to 0.0143 per water-horsepower-day. The maintenance figures computed in Table 7 in the next section average \$0.00315 per water-horsepower-day. The total of operating labor and maintenance costs is then \$0.0174 per horsepower-day.

REPAIRS TO PUMPS AND MOTORS

Data on repairs to pumps and motors suffer from the same imprecise terminology as mentioned in the previous section. Table 7 shows the means of arriving at a figure for our pur-

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* This relation is erroneously stated in Reference 5. The 0.8 cent per horsepower-hour given there does not correspond to 0.5 cent per kilowatt-hour at 84 percent efficiency. The 0.8 cent per horsepower-hour is, however, correct, the error being in the kilowatt-hour relationship.

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Table 7. EXPERIENCED COSTS FOR PUMP AND MOTOR REPAIRS, AND MAINTENANCE

Item	Reference	Cost	Year applicable	Conditions assumed[a]	Computed or assumed water HP	Computed $/year (1961)	$/water-HP-year (1961)	$/water-HP-day (1961)
1. Fluid and gear ends piston pump, maintenance and repairs costs, injection wells	36	$0.000343/bbl	1950?	10,000 bpd well 100 HP pump	84	1,970	23.4	0.0642
2. Operating and maintenance costs, plunger pump, injection wells, used as comparable with 1	36	$0.000539/bbl	1950?	"	84	3,090	36.8	0.098
3. Piston pumps maintenance costs								
0 to 20 gpm	Leonard[31]	$125 to 250/yr	1951	Use highest in range for both gpm and cost, take 900 psi	10.6	352	33.2	0.0910
4. 20 to 40 gpm		$150 to 175/yr			21.2	246	11.6	0.0316
5. 40 to 80 gpm		$200 to 250/yr			42.6	352	15.0	0.041
								Average 0.065
6. Pump and motor repairs, oil pipeline stations	Elam[5]	$1.00/HP yr	1955	Large HP	100 to 500	--	1.22	0.00333
7. Elec motor (only) maintenance	35	$0.50/HP yr	1961	60 to 500 HP Pump maint 2x motor maint Labor ≈ $3/hr instead of $5	50 to 420	--	1.07	0.00296

[a] General: Adjusted by Factory Plant Maintenance cost index.[37]
Load factor 100%, 24 hr operation, 84% wire-to-water efficiency.

poses. The cases chosen were those for which the context seemed to imply that the subject was "repairs," that is, a breakdown or overhaul in which the equipment was out of service when worked on. This may be distinguished from "maintenance," which in the present study denotes services to equipment while it is essentially still in operation or while shut down for a few minutes for maintenance purposes, that is, lubrication, cleaning gland packing, etc. Because of its small magnitude compared with the others it is possible that item 6 actually refers to maintenance rather than to repairs. Also shown, as item 7, is an estimate for electric motor maintenance (as here defined[35]) which, when adjusted to take into account the pump maintenance separately, becomes a figure of the same magnitude as item 6. When plotted (not shown) the data may show a trend of dollars per horsepower-day increasing with water horsepower, and to high values at low water horsepowers below 20. There are, however, not enough data to substantiate such a trend, and in the present study the average $0.065 per horsepower-day will be used for pump and electric motor repairs.

GENERAL AND ADMINISTRATIVE EXPENSE FOR PUMPING

Some general and administrative expense is allocable to the costs of pumping outlined above. They will be taken as 20 percent on labor estimated to be 50 percent of repairs expense, and 100 percent of operation labor and maintenance expense. In addition there will be applied 7 percent on purchased materials estimated at 50 percent of repairs. This comes to a total of $0.0122 per water-horsepower-day.

SUMMARY OF PUMPING COST FACTORS

The pumping cost factors are summarized in Table 8.

Table 8. PUMPING COST FACTORS

Factor	$/water-HP-day[a]
Energy	0.1068
Operating labor and maintenance	0.0174
Repairs to pumps and motors	0.0650
G and A	0.0122
Total	0.2014 x water HP = $/day
At 84% wire-to-water efficiency:	0.1692 x Driver HP = $/day
Fixed costs pump and drive capital x $\frac{0.258}{1,000}$ = $/day	

[a] Those items given in dollars per horsepower-day are summed and multiplied by the Driver horsepower to give a dollars per day cost. The daily fixed charge on the capital is obtained by the 0.258 per 1,000 multiplier.

Economic Diameter For Injection Wells

In the previous study,[5] the economic diameter for injection wells was taken from a conventional economic diameter nomograph for process piping. One of the goals of the present study is to compute economic diameters by use of the actual parameters of the injection wells situation. As the diameter of the well, that is, of the production casing, is increased, the cost of the well and the daily operating cost attributable thereto increases. In contrast, as the diameter is increased, the head-loss in the casing due to friction is decreased. The required horsepower for pumping is, therefore, reduced. Accordingly pumping costs decrease as diameter increases. The economic diameter is the one that makes the sum of these two competing costs a minimum.

The well costs are composed only of the fixed daily charges on the well. The costs associated with pumping, that is, with pressure, are the valve, the pump itself, and the pumping costs based on horsepower as outlined above.

EFFECT OF FLUID DENSITY ON PRESSURE AND HORSEPOWER

In the previous study[5] it was recognized that the computation of horsepower from formation parameters could not be done with any generality. Instead, operating casing head pressures were chosen to represent the median, the approximate 25 percentile, and the 90 percentile of experienced injection wellhead pressures, namely 260, 0, and 900 psi, respectively. The present study requires some elaboration of that parameter.

In the prior study the density of the fluid was unchanged at 1.11 and the casing head pressures referred to correspond to fluid of that density. In the present study an essential element is the variation of density of the injected fluid corresponding to the three concentrations used in the study. If the density is assumed to be the same as that of an NaCl solution of corresponding total solids concentration at 68° F, these densities will be as follows:

Total solids, mg/liter	300	9,000	180,000	300,000
Density, g/ml	1.000	1.005	1.116	1.187

The 180,000 milligrams per liter case is included because it happens to be a case that was computed in Part 1 of the study.[5] The actual densities here chosen differ slightly from those used in that report for the corresponding concentrations.

The operating casing head pressure is composed of the static pressure at the casing head, plus the pressure drop to overcome formation resistance, plus the friction drop in the casing. The friction drop in the casing, in psi, is proportional to fluid density, but its contribution to operating casing head pressure is small. A much greater variation in operating casing head pressure is, however, brought about by the change of static pressure with density. For the present study it will be assumed that the standard pressures to be chosen refer to pressures when the fluid has a density of 1. 116. This density was chosen because it approximates the density used in the previous study,[5] which in turn was chosen to be typical of oil field pressures.

Pressures (P^o_{ch}) exclusive of friction drop were computed for the three densities, the three standard pressures, and at the depths of interest. For example, if a 10, 000-foot well has a standard pressure of 260 psi, it will have a pressure, exclusive of friction drop (P^o_{ch}), of 762 when the fluid density is 1. 000, and of 14. 4 psi when the fluid density is 1. 187. The effect of fluid density is to increase the horsepower required when the density is less than standard (1. 116) and to decrease it when the density is greater than standard. This effect on static pressure outweighs the opposite effect on friction drop measured as psi.

PRESSURE RELATIONSHIPS IN INJECTION WELLS

An underground reservoir is characterized by a given reservoir pressure that must be exceeded if fluid is to be injected into the reservoir. Thus the bottom hole pressure must exceed the reservoir pressure by a differential constituting the driving force. These relationships may be expressed as follows:

$$P_b = P_r + \Delta P_d \qquad (2)$$

where:

P_r = reservoir pressure at well bottom, psig

P_b = bottom hole pressure, psig

ΔP_d = bottom hole driving pressure, psig

The bottom hole pressure is made up of the casing head pressure, plus the pressure of the fluid column, minus the pressure drop due to friction of flow down the casing, represented as follows:

$$P_b = P_{ch} + P_c - \Delta P_f \qquad (3)$$

where:

P_{ch} = operating wellhead pressure

P_c = bottom pressure due to weight of fluid column, psi

ΔP_f = pressure drop due to pipe friction, psi

Combining the above there is obtained:

$$P_{ch} = \left[P_r + \Delta P_d - P_c \right] + \Delta P_f \qquad (4)$$

In the previous study it was shown that ΔP_d varies greatly, particularly with formation permeability, so that, though reasonable limits can be set, the quantity cannot be generalized. Accordingly for the previous report there were chosen for computation the three casing head pressures corresponding to the above equation. And, as explained in the previous section, this applied to a fluid of density 1.110.

In the present study, however, an essential element comprises an investigation of optimum casing size. Accordingly the assumption of fixed operating casing head pressures is untenable. In the following it will be demonstrated that the variable in operating casing head pressure with wall diameter may be restricted to the friction drop component.

There are two elements in the above equation that vary with well diameter. These are ΔP_d and ΔP_f. As has been described, ΔP_d is subject to very large variations due to formation permeability, and since these are not subject to generalization, a reasonable standard cannot be chosen. Furthermore, as detailed in Reference 5, ΔP_d varies according to the logarithm of well diameter. Thus its relative variability with well diameter is small compared with the variability of ΔP_f, which varies accord- to the 1.17 power of diameter (in the Hazen-Williams formula). Some of these numerical relationships are shown in Table 9 in which pressure drops due to formation resistance and pipe friction are computed for a range of casing diameters and at the extreme reasonable limits of formation permeability. Inspection of this Table shows first that the variation of ΔP_d with permeability is so great as to overshadow the pressure drop completely owing to pipe friction; and second that the variation in pressure drop with casing diameter is much greater for friction than for formation resistance.

The above reasoning and magnitudes lead to the conclusions that the pressure drop due to formation resistance must be included in the arbitrary pressure parameters and the small effect of casing diameter on ΔP_d must be neglected in the economic optimum computations.

Table 9. PRESSURE DROPS DUE TO FRICTION, ΔP_f, COMPARED WITH THOSE DUE TO FORMATION RESISTANCE, ΔP_d, psi (100 ft of face)

	OD, in.		
k, darcys	2-7/8	7	13-3/8
2 million gpd			
ΔP_d 0.020	—	19,000	—
ΔP_d 3.0	147	127	61
ΔP_f[a]	—	457	23
100,000 gpd			
ΔP_d 0.020	1,100	950	455
ΔP_d 3.0	7.3	6.8	3.0
ΔP_f[a]	203	2.0	—
1,000 gpd			
ΔP_d 0.02	11.0	9.5	4.5
ΔP_d 3.00	0.07	0.06	0.03

[a] In 7,000 feet of casing at density = 1.005.

Accordingly the pressure parameters for the present study are standardized in the following terms:

$$P_{ch}^{s} = \left[P_r + \Delta P_d - P_c \right] \qquad (5)$$

then:

P_{ch}^{s} = 0, 260, and 900 psi, when d = 1.116 and fluid level is at the surface.

This means that the standard pressures are chosen so that the casing head pressures, exclusive of friction drop when the fluid density is 1.116 and fluid level is at the surface, are 0, 260, and 900 psi, respectively.

In the computations to be made later on Costs of Injection, the above becomes an accurate expression for casing head pressures, exclusive of friction drop, at the casing diameters chosen. Here, however, in the economic optimum computations, some approximation is introduced owing to the fact that the influence of diameter on ΔP_d has been neglected. At high permeabilities the error in the economic diameters introduced by this approximation will be small because at the economic diameters ΔP_d is small compared with ΔP_f, and furthermore the variation in ΔP_d with diameter is small compared with the variation in ΔP_f. When, however, the permeability of the formation is very small, ΔP_d becomes very large compared with ΔP_f and thus the variation of $[\Delta P_d + \Delta P_f]$ with diameter becomes more like that of ΔP_d. This means that the pressures will not rise as rapidly with decreasing diameter as has been calculated. Thus it may be concluded that at low permeabilities the true economic optimum diameter for a given formation and depth will be smaller than will be calculated later, but whether the true costs will be more than or less than those computed later cannot be deduced short of actual computation.

SELECTION OF CASING PROGRAM

Casing programs for the conventional-diameter wells computed on page 24 followed conventional oil field practice. Here, however, in the economic diameter computations, nonconventional diameters are involved and thus the casing program should be worked out from the basic principles thereof. Casing selection is a specialized and complicated activity, the goal of which is to devise the cheapest casing strings that will survive the three major hazards during installation and operation, namely tension, collapse, and burst. Four grades (strengths) of steel are ordinarily used in casing designated F, H, J, and N. In addition each casing size (outside diameter) is made in a number of wall thicknesses (that is, weights, lb/ft). Each grade and weight has a different resistance to failure by tension, collapse, and burst. Tension refers to failure resulting from the weight of casing below, suspended from the top. The joint is the weakest part of the string, and some increase in resistance to tension is achieved by using "long threads" rather than short threads on the joints. Collapse refers to crushing from external pressure, as when empty casing sealed at the bottom is lowered to considerable depths and pressurized by the weight of the drilling fluid. Burst refers to failure resulting from pressures inside the casing. Casing design takes all these factors into account and selects the grades and weights to meet the hazards at the minimum cost.

It was not possible to take these factors into account within the scope of the present study. Instead collapse and burst were not accounted for and casing design was based on approximate tension requirements. The conventional safety factor of 2.0 was used. In some cases the design approached the limits and in some cases exceeded the limits of available casing strengths. This is particularly true in the large-diameter deep wells. In these cases no doubt the special supergrade (deep-well casing) is called for, but since cost data were not available on this grade, N costs were used in place of it. It appears likely that any large-scale use of 2 million gpd deep wells would require an enlargement of the present boundaries of conventional oil well casing practices and grades.

EXEMPLARY COMPUTATION FOR ECONOMIC OPTIMUM DIAMETER

The following computation for 2 million gpd, 7,000-foot, 900 psi, and a 7-inch casing is offered to illustrate the method.

Fluid density 1.000, $P_{ch}^{s} = 900$

P_{ch}^{o} (casing head pressure exclusive of friction at that depth)
(1.116 - 1.000) x 0.4331 x 1,000 = psi/M ft = +50.2
900 + 7 x 50.2 = 1251.4 P_{ch}^{o}

Friction read from conventional chart or nomograph, Hazen and Williams,
C = 100, 2 million gpd, 7-in. OD : ΔH = 150 ft/1,000 ft
150 x 7 (M ft) x 0.4331 x 1.000 = 455, Δpsi due to friction, ΔP_f

$$\begin{aligned} P_{ch}^{o} &= \underline{1251} \\ P_{ch} &= 1706 \end{aligned}$$

$\therefore$ use piston-type pump

Valve

7 in., 1750 psi valve read from graph (not shown)
$550/in. x 7 = $3,850 cost of valve
$3,850 x 0.258/1,000 = $0.99/day fixed charge on valve

Horsepower

$$1,706 \text{ psi} \times \frac{2 \text{ million gpd}}{2468.6} \times 1.000 \text{ density} = 1,382 \text{ Water HP}$$

at wire-to-water efficiency 0.84 = 1,645 Driver HP.
Read Figure 7. $92/DHP x 1,645 = $15,130 cost of pump and drive
$15,100 x 0.258/1,000 = $39.04/day fixed charge on pump

other pumping costs
0.1692 x 1,645 DHP = $278.33/day other pumping costs

Total, valve, pump, pumping $318.36/day

Well cost (except valve)
$100,200 x 0.258/1,000 = 25.85/day, fixed charge on well

Total daily cost $344.21/day

The friction drop will actually be less than that indicated since plastic-lined pipe has a Hazen and Williams coefficient of 140 when new. Standard oil field practice uses, however, a coefficient of 100 as a safety factor and to cover decreased capacity due to scaling, etc., with age.

Computations of the above type were made for each set of parameters at three or four casing diameters. The well costs and the sum of the valve pump and pumping costs were plotted separately against diameter, and interpolations were made to obtain the sums (that is, the total cost) at various diameters. The sums were plotted on a larger scale immediately surrounding the point of minimum cost and there was determined not only the theoretical economic optimum diameter but also the range of diameters that would cause a cost increase of less than $0.001 per thousand gallons, for example, in the 2 million gpd case, $2 per day. In some cases well costs were interpolated.

In the actual computations a short-cut technique was used, which reproduced the exemplary computation but took much less time.

ECONOMIC DIAMETER, 2 MILLION gpd

The results of these computations for 2 million gpd are shown in Table 10. The cost minimums were moderately broad, frequently 0. 5 theoretical inches on each side of the theoretical optimum, but in no case except as indicated in the Table were alternate choices of actual standard-size casing permitted. In the cases in the Table indicated with brackets the difference was slight, with the slight preference to the diameter outside the bracket. In the other choice case the 9-5/8 and 10-3/4 showed equal costs within the limit of accuracy of the computations. Since the basic data have considerably greater variation than the computations, it is uncertain which casing would actually satisfy the minimum. In later use of these cases the smaller diameter was chosen on the basis of being closer to conventional practice and also of minimizing the nonsalvageable investment in the well at the expense of salvageable investment in the pump.

Table 10. ECONOMIC DIAMETER, in. OD PRODUCTION CASING, 2 MILLION gpd

Depth, ft	d, g/ml	P^S_{ch}, psi		
		0	260	900
3,000	1.000	10-3/4	(10-3/4)[a]	(10-3/4)
	1.005	10-3/4	10-3/4	10-3/4
	1.187	8-5/8	10-3/4	10-3/4
7,000	1.000	(10-3/4)	(9-5/8)	9-5/8 or 10-3/4
	1.005	10-3/4	9-5/8 or [10-3/4]	" "
	1.187	8-5/8	10-3/4 or [9-5/8]	" "
12,000	1.000	(8-5/8)	(9-5/8)	(9-5/8)
	1.005	8-5/8	9-5/8	9-5/8
	1.187	8-5/8	9-5/8	9-5/8

[a] Numbers within parentheses have been inferred from adjacent entries.

ECONOMIC DIAMETER, 100, 000 gpd

Computations similar to those in the preceding section were made for the 100, 000 gpd case with results as shown in Table 11. The cost difference between adjacent casing diameters was quite small, but since $0. 001 per thousand gallons amounts to only $0. 10 per day, no pair of diameters fell within this range. The theoretical economic diameter is smaller than 2-7/8 in some cases, but 2-7/8 inches was taken as the smallest size tubing that would under present technology be run in a well. Tools and workover methods for smaller diameters have not yet been brought into use, so that operators are reluctant to construct smaller wells.

Table 11. ECONOMIC DIAMETERS, 100,000 gpd

Thousand ft	density[a]	psi		
		0	260	900
3	1.005	2-7/8	2-7/8	2-7/8
	1.187	2-7/8	2-7/8	3-1/2
7	1.005	2-7/8	2-7/8	2-7/8
	1.187	2-7/8	4-1/2	4-1/2
12	1.005	3-1/2	3-1/2	3-1/2
	1.187	2-7/8	3-1/2	3-1/2

[a] 1.000 density is taken to be same as 1.005.

The 1.000 density case is taken to be the same as the 1.005 since the horsepower difference is so small. To check this conclusion economic diameters were worked out for the 1.000 density in a few cases and were found to be identical with the 1.005 density. It is interesting to note that in a few cases the diameter next larger than the optimum was operating on vacuum, that is, without a pump. Nevertheless, in most cases, the pumped well of the smaller diameter showed the lower cost.

ECONOMIC DIAMETER, 1,000 gpd

At 1,000 gpd the friction drop through 2-7/8-inch-outside-diameter tubing would be about 0.0035 foot per 1,000 feet. The friction pressure drop at 12,000 feet would be 0.02 psi, and the corresponding driver horsepower, 9×10^{-6}. Accordingly in this and larger size tubing the difference in horsepower, thus cost, would be completely negligible, and since 2-7/8 is the smallest permitted diameter, this means that the economic diameter for 1,000 gpd under all conditions is 2-7/8-inch tubing.

Costs Of Injection

By using data developed above on component costs and fixed charges on capital as on page 34, injection costs were computed for the 54 cases of densities 1.187 and 1.005, flows of 1,000, 100,000 and 2 million gpd, depths of 3, 7, and 12 thousand ft, and standard pressures of 900, 260, and 0 psi. The results are shown in Table 12 and are plotted in Figures 8 and 9.

A few computations were done for density 1.000 from which it was concluded that the investment and injection costs for 1.000 were so close to those for 1.005 as to make their separate computation unnecessary. Examples illustrating this are shown in Table 13.

Table 13. EFFECT OF DENSITY ON INVESTMENT AND INJECTION COSTS

	100,000 gpd, 3,000 ft, 900 psi		100,000 gpd, 12,000 ft, 900 psi		100,000 gpd, 3,000 ft, 0 psi	
	d = 1.005	d = 1.000	1.005	1.000	1.005	1.000
P^o_{ch}	1,044	1,051	1,426	1,502	144	151
P_{ch}	1,131	1,158	1,514	1,619	231	237
HP	54.9	55.8	77.5	78.0	11.2	11.4
$/1,000gal	0.174	0.175	0.648	0.649	0.0850	0.0855
$/gpd	0.313	0.313	2.004	2.005	0.256	0.257

COMPARISON WITH EARLIER STUDY

It is inevitable that the injection costs developed here will be compared with those developed in a much more preliminary fashion in Reference 5. For a middle case of 7,000 feet and 260 psi the comparison is shown in Figure 10. Of course the comparison might be different at different depths and pressures. It is seen that the earlier work reasonably reproduces the present more detailed study, both as to trend and to placement. It should be noted that the earlier work was based on 1957 costs while the present is based on 1961 costs. Also the 260 psi has a different significance in the two studies. In the earlier study

Table 12. COSTS OF INJECTION, FLUID DENSITY: 1.187
1.005

Depth, thousand ft	Wellhead pressure except friction, P^o_{ch}, psi	Operating wellhead pressure, P_{ch}, psi	Driver HP (rounded)	Production casing, OD, inches	Investment well, pump, valve, $/gpd	Injection cost, $/1,000 gal	Injection cost, $/day
	Standard press: 900 psi			1,000gpd			
3	808 1,044	Same as P^o_{ch}	0.5 0.5	2-7/8 2-7/8	26.2 26.3	6.84 6.86	6.84 6.86
7	685 1,236	" "	0.4 0.6	" "	69.6 69.9	18.02 18.10	18.02 18.10
12	532 1,476	" "	0.3 0.7	" "	187.7 188.2	48.40 48.80	48.40 48.80
	Standard press: 260 psi						
3	168 404	Same as P^o_{ch}	0.1 0.2	" "	24.4 25.9	6.32 6.72	6.32 6.72
7	45 596	" "	0.03 0.3	" "	67.9 69.5	17.50 17.98	17.50 17.98
12	Vacuum 856	" "	– 0.4	" "	184.9 198.0	47.80 48.50	47.80 48.50
	Standard press: 0 psi						
3	Vacuum 144	Same as P^o_{ch}	– 0.1	" "	23.2 24.4	6.23 6.31	6.23 6.31
7	" 336	" "	– 0.2	" "	66.6 68.0	17.20 17.53	17.20 17.53
12	" 576	" "	– 0.3	" "	184.9 187.8	47.80 48.55	47.80 48.55

Table 12. (continued)

Depth, thousand ft	Wellhead pressure except friction, P^o_{ch}, psi	Operating wellhead pressure, P_{ch}, psi	Driver HP (rounded)	Production casing, OD, inches	Investment well, pump, valve, $/gpd	Injection cost,	
						$/1,000 gal	$/day
	Standard press: 900 psi			100,000gpd			
3	808 1,044	842 1,131	48 55	3-1/2 2-7/8	0.316 0.313	0.163 0.174	16.3 17.5
7	685 1,236	704 1,142	40 70	4-1/2 2-7/8	0.794 0.755	0.273 0.313	27.3 31.3
12	532 1,426	667 1,594	38 78	3-1/2 3-1/2	1.98 2.004	0.579 0.648	57.9 64.8
	Standard press: 260 psi						
3	168 404	271 491	16 24	2-7/8 2-7/8	0.260 0.260	0.093 0.107	9.31 10.7
7	45 596	64 803	3.7 39	4-1/2 2-7/8	0.756 0.714	0.203 0.250	20.3 25.0
12	Vacuum 836	28 972	1.6 46	3-1/2 3-1/2	1.94 1.976	0.503 0.588	50.3 58.8
	Standard press: 0 psi						
3	Vacuum 144	11 231	0.6 11	2-7/8 2-7/8	0.243 0.256	0.064 0.085	6.39 8.55
7	Vacuum 336	27 543	1.5 26	" "	0.680 0.707	0.178 0.227	17.8 22.7
12	Vacuum 576	45 690	2.6 33	" 3-1/2	1.85 1.97	0.485 0.565	48.5 56.5

	Standard press: 900 psi			2 million gpd			
3	808 1,044	836 1,068	958 1,075	10-3/4 10-3/4	0.0795 0.0850	0.102 0.109	203.1 218.7
7	685 1,236	793 1,327	905 1,286	9-5/8 9-5/8	0.1218 0.1475	0.109 0.146	218.6 293.8
12	532 1,476	719 1,634	824 1,584	" "	0.2659 0.3032	0.138 0.212	276.6 424.4
	Standard press: 260 psi						
3	163 404	191 427	217 414	10-3/4 10-3/4	0.0368 0.0529	0.0278 0.0487	55.7 97.3
7	45 596	110 692	126 671	" 9-5/8	0.1036 0.1170	0.0360 0.0869	72.0 173.9
12	Vacuum 836	78 993	89 963	9-5/8 "	0.2282 0.2727	0.0664 0.1518	132.9 303.5
	Standard press: 0 psi						
3	Vacuum 144	5 167.4	6 162	8-5/8 10-3/4	0.0242 0.0364	0.0067 0.0231	13.5 46.2
7	" 336	11 391	13 379	" "	0.0716 0.1094	0.0195 0.0603	39.1 120.5
12	" 576	20 904	23 877	" 8-5/8	0.1869 0.2282	0.0502 0.1330	100.3 266.1

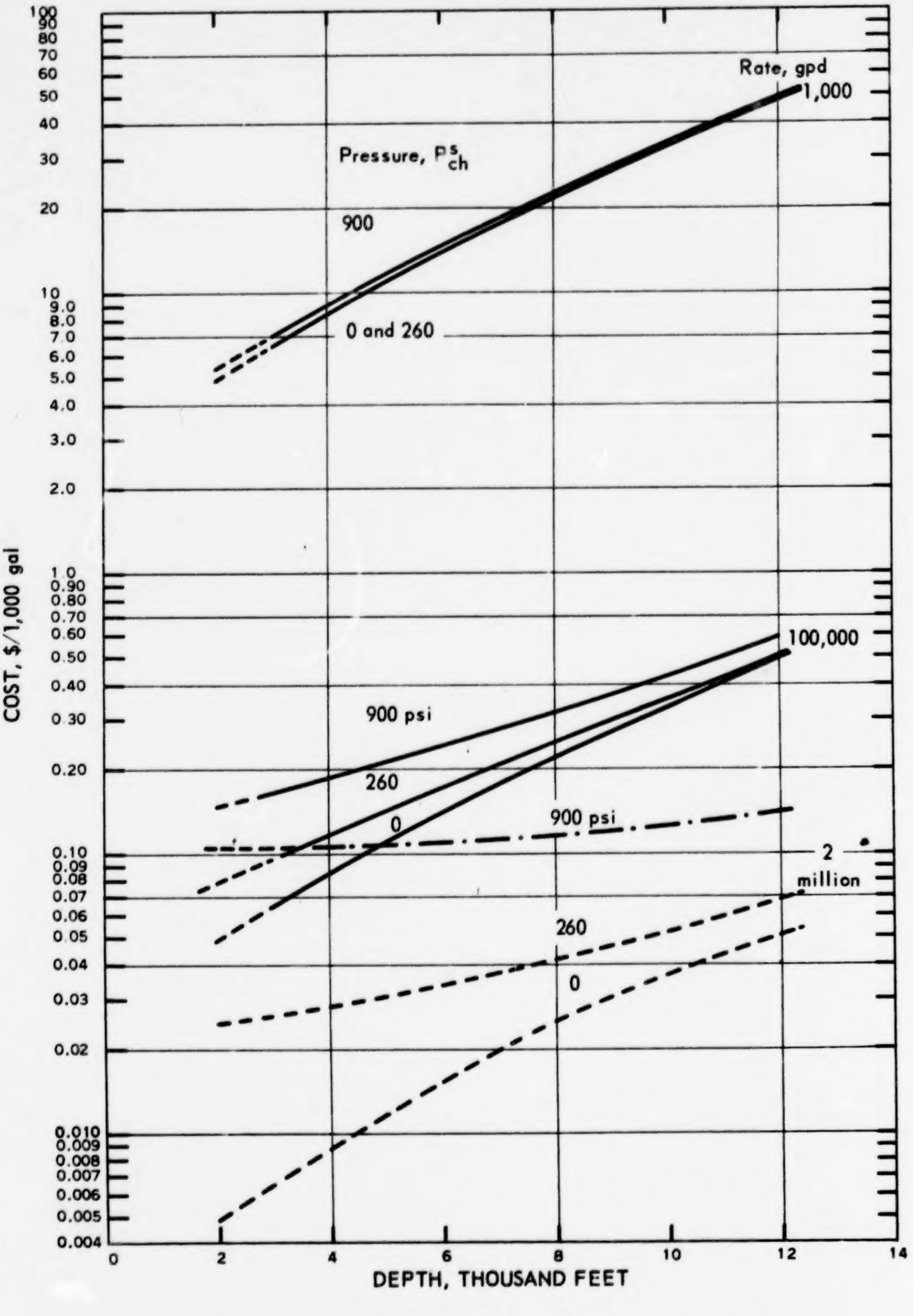

Figure 8. Cost of injection, 1961 (fluid of 1.187 density against 0,260, and 900 psi standard wellhead pressure).

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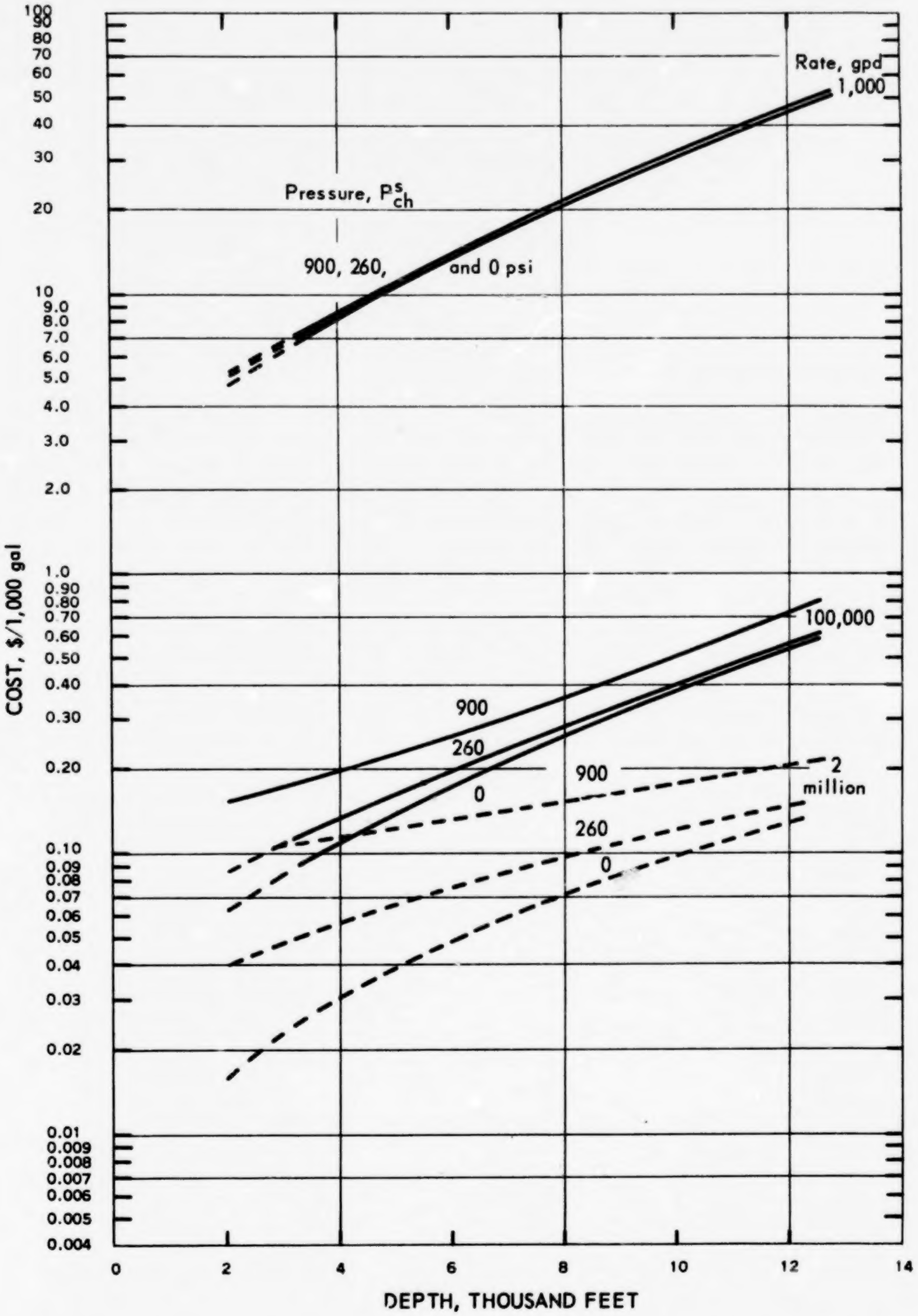

Figure 9. Cost of injection, 1961, (fluid of 1.005 or 1.000 density against 0,260, and 900 psi standard wellhead pressure).

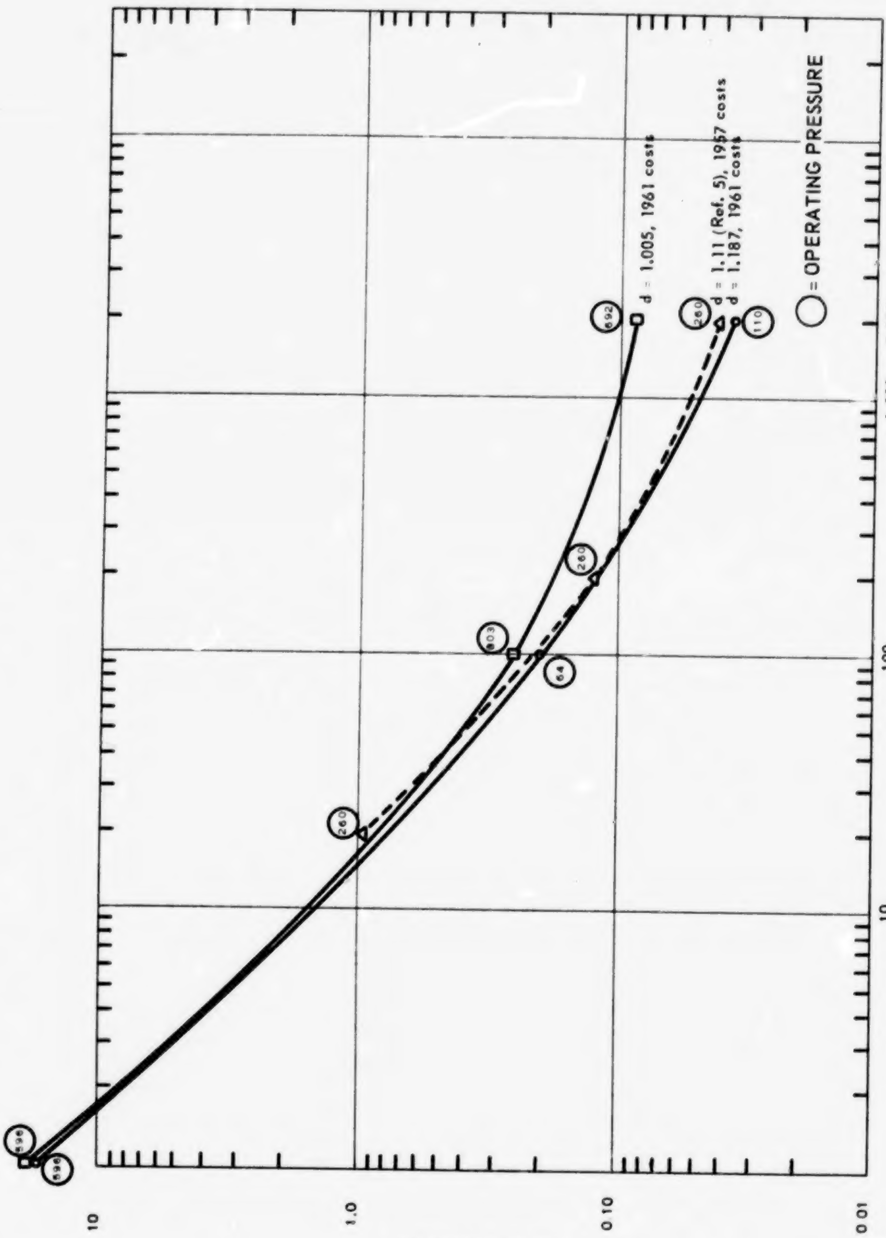

Figure 10. Injection costs compared, 7,000 ft, 260 psi (see text).

260 psi represented the operating casing head pressure, P_{ch}, for the fluid in question. The actual operating pressures are shown in circles adjacent to the points in Figure 10. It is seen that the operating pressures are actually quite different in the three cases; thus the horsepower requirement is quite different and the optimum casing size might be different. For example, the casing size used for the 2 million gpd case in the earlier study was 13-3/8 inches, while in this study for the present example it has been optimized at 9-5/8 inches. Accordingly the seeming agreement between the two studies in the example must be considered as fortuitous and the result of the counterbalancing of competitive influences. In the present study the rationale of the standard pressures was chosen to compare situations with reservoir pressures and permeabilities.

Conditioning Waste For Injection

It is very difficult to generalize on the treatment and treatment costs of conditioning the waste for injection. The treatment required depends upon the nature of the formation, the composition of the connate water, and the composition of the waste. Different degrees and types of treatment are necessary to condition various wastes to make them compatible with existing underground conditions. In addition to these nongeneralizable factors is the variability of waste composition, which depends on the particular advanced waste treatment process used, and also on the degree of conditioning that occurs, incidentally or deliberately, as a part of the advanced waste treatment processes.

For example a common cause of incompatibility is the release of CO_2 from a waste, which causes supersaturation i· $CaCO_3$, which in turn plugs the formation because of $CaCO_3$ precipitation. Aeration processes are used to release the CO_2 and this supersaturation. If, however, the advanced waste treatment process consists of a heating or distillation step, it is almost certain that any latent $CaCO_3$ supersaturation will have been released during the treatment process itself, which in turn will have obviated the need for the step in the conditioning process. On the other hand, such advanced waste treatment processes as solvent extraction may leave residues of solvent or other reagents in the waste, which would necessitate an additional treatment step.

The literature on conditioning wastes for injection is large and will not be referenced here. The major components of interest are:

Suspended solids, which plug the pores directly;

physically supersaturated components, for example, $CaSO_4$, which will slowly precipitate in the formation;

ions that can cause chemical precipitation, for example, Ba^{++}, which will precipitate as $BaSO_4$, when it reaches a sulfate formation water;

Fe^{++}, which can oxidize to insoluble Fe^{+++};

organic polymerizable material, which may form insoluble precipitates;

organic materials, which may form nutrients for microorganisms; and

oxygen and CO_2, which cause corrosion and develop corrosion products.

Other undesirable reactions may occur that require conditioning steps. For example, certain clays found in underground formations are subject to swelling when their natural salt-water environment is replaced by a more dilute liquid. The consequent swelling of the clay material already in the pores of the formation, or constituting the matrix itself, may greatly reduce the permeability of the formation.

Since it is patently not possible to explore all these parameters, the present study will confine itself to an analysis of a relatively simple type of treatment such as is typical of treatment of oil field brines for injection.

Some of the information is drawn from the records of the operation of the East Texas Salt Water Disposal Company.[34, 36, 38] It should, however, be noted that this Company, through good management and engineering and operating practices, has carried cost reduction to a high degree. A corresponding degree of management and operation efficiency would have to be reached if these costs are to be duplicated.

The East Texas conditioning operation consists of chemical flocculation with lime and alum, sedimentation, filtration, and chlorination. The standard plant for conditioning 10,000 barrels per day consists of pressure filters, treating pits, backwash pits, aerator, receiving tank, clear tank, chemical house and feeder, overflow pit, and meters, etc. Equipment is kept as simple as possible and treatment is not extreme, for it has been found cheaper to reduce the efficiency of treatment and take an additional cost for occasional well cleaning, rather than use extreme treatment without well cleaning. Costs estimated on this basis must be considered as minimal for the type of treatment utilized, which is mostly for $CaCO_3$, FeS, oil, and microorganisms.

Other data over a range of sizes pertain to similarly simple conditioning plant experience in California.[39] These plants do not use chemical coagulation but employ a filter aid for filtration through a sand or a leaf filter. The chemical treatment with chlorine and polyphosphate is for control of microorganisms and of scale. The plants consist of charging pumps, slurry pumps, slurry tank, precoat tank, filters, and filtered water storage.

CONDITIONING PLANT COSTS

The cost of components of the 10,000-barrel-per-day conditioning plant is estimated from data supplied by the East Texas Salt Water Disposal Company.[34, 36] The two references agree rather closely when allowances are made for rising cost index, and from them choices have been made as follows:

3 pressure filters, 96 x 54 in., plastic-lined, 45 psi, coal or sand bed (run in parallel)	$ 7,500
Gunite backwash pit, 60 x 60 x 6 ft	1,000
Gunite treating pit, 63 x 133 x 10 ft	11,000
500-barrel redwood receiving tank	3,000
10-tray aerators, 14 x 24 x 14 ft high, yellow pine on slab, 28 x 56 ft	2,300
Chemical house and mixing chamber, 14 x 14 ft	1,000
250-barrel redwood clear tank	1,700
Earthen overflow pit	1,000
Water meter and chlorine rotameter	1,000
Chemical feeders	125
Piping and miscellaneous	7,375
Engineering and construction supervision - 10%	3,700
General and administrative - 10%	3,700
Total cost (1961)	$44,400

A cost breakdown for a typical 3,000 bpd California plant is drawn from Reference 39:

	(as of 1952)
200 ft^2 Monel filter	$10,500
Filter aid tank	700
Precoat tank	400
Valves	1,500
Chlorinating equipment	2,000
Meters	600
Phosphate injection equipment	400
2 centrifugal charging pumps	1,025
Lined clear water tank	1,000
Electrical equipment	2,000
Pipe and concrete	3,000
Paint	2,000
Labor	5,000
Total	$30,125

Wheeler[39] supplies plant costs on eight existing California plants and indicates that the cost of the typical plant, estimated above but including the injection pumps, would be increased by one-third in doubling the size.

In all then, data are available on 11 existing or typical plants as shown in Table 14.

Table 14. COSTS OF CONDITIONING PLANTS

Plant	Date	Thousand gpd	Current year, cost	1961 cost ex pump	$/gpd (1961)
1	1948	246	34,750	45,800	0.186
2	51	6.8	18,000	21,600	3.18
3	52	2.52	23,000	29,800	11.90
7	50	25.2	8,600	9,500	0.377
8	52	162	45,000	51,400	0.316
10	50	50.5	50,000	68,500	1.36
17	50	84.0	20,000	25,500	0.303
18	47	566	80,000	107,600	0.190
Estimated	52	126	47,711	40,600	0.322
Estimated	52	252	63,600	(38,300)	(0.16)
E. Tex.	1961	420	—	44,400	.106

The 1961 costs exclusive of pump were developed as follows. The current year's cost was adjusted to 1961 costs by application of the Marshall and Stevens Equipment Cost Index for petroleum industry equipment. The barrels-per-day capacity and the wellhead pressure are given as part of the original data. From these was computed the driver horsepower. This figure was used to estimate the cost of the injection pumps and drivers involved. The California plants typically use natural-gas engines rather than electric motors. Accordingly it was necessary to develop a cost correlation for gas-engine-driven Triplex pumps similar to the one referred to in Figure 7. This was done by obtaining quotations on natural gas engines, correlating the costs according to maximum continuous horsepower, and combining them with the cost of Triplex pumps. When this was done it was found that the costs were quite close to those for electric motor drives in the lower horsepowers and lower than those in the higher horsepowers.

The correlation of these conditioning plant costs according to capability is shown in Figure 11. The 10 points in the trend band have an average deviation of ± 30 percent, all 11 points a deviation of ± 38 percent. The East Texas plant, though somewhat different in makeup, correlates well with the others.

From the trend line indicated the following costs were chosen.

1,000 gpd plant costs (1961) excluding pump	$25,000
100,000 gpd	40,000
2 million gpd	56,000

REPAIRS TO CONDITIONING PLANT

Costs of repairs to the conditioning plant are available only for the East Texas plant. Reference 34 supplies the following item-by-item breakdown.

	$ per year
Clean pit, once a year	$ 150
Replace pit baffles, once in 10 years	100
Clean aerator trays, once a year	300
Recharge filters, once a year	350
Repair meters, once a year	25
Replace overflow pit, once in 10 years	100
Total	$1,025

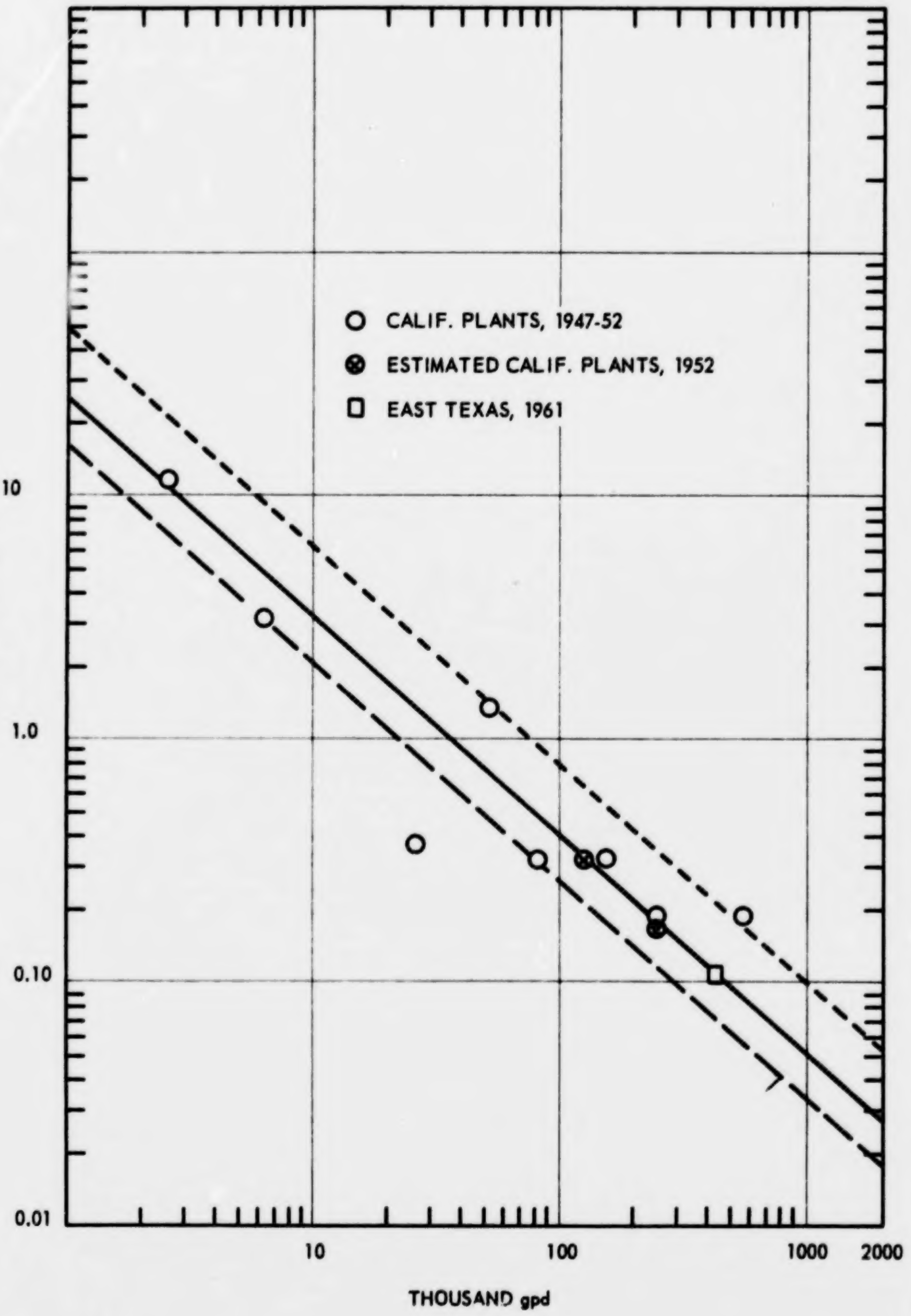

Figure 11. Cost of plants for conditioning injection water.

Independent data from the 1956 Financial Statement of the Company[38] supply the following information on repairs from the plant and well account.

Repairs to buildings	$ 548
Repairs to measuring equipment	1,377
Repairs to tanks and filters	17,192
Repairs to pits	6,567
Repairs to treating equipment	17,924
Total	$43,608

Since there are 37 operating conditioning plants this comes to $1,180 per year per plant, a close check on the individual items listed above. An average of $1,152 per plant year may be taken. Thus

0.0714/1,000 x plant cost = daily repair cost,

which is based on the plant cost of $44,400.

OPERATING COSTS FOR CONDITIONING

Reference 39 also supplies the cost of treatment in cents per barrel for 12 California plants. These must be adjusted for our purposes. They include the costs of operating the injection pumps. Stevenson[35] estimates the cost of gas engine operation as follows:

Gas 14 ft^3/DHP hour at say 20¢/thousand ft^3	= $0.0673/DHP day
Engine maintenance $8/DHP year	= 0.0219/DHP day
Engine oil 7% of fuel (see below)	= 0.0048/DHP day
Total, fuel, oil, and engine maintenance	= $0.0940/DHP day

This may be checked with Reference 39, which shows daily estimated costs for gas-engine-driven pumps judged from the cost to total 80 horsepower:

Fuel	$ 7.05/day	
Oil	0.50/day	
Maintenance	2.50/day	
Total	$10.05/day	$0.126/DHP day

It is assumed that maintenance in each of the above cases is meant to include repairs in the sense of the present study.

Accordingly the only other pump and drive item to be withdrawn would be operating and maintenance labor, which as shown above, may be estimated at \$0.0174 per DHP per day. It is concluded, therefore, that the pump and engine operating costs associated with the California data amount to \$0.10 per DHP per day. The daily current year costs were adjusted by subtracting the corresponding amount, based on the DHP above, to obtain a dollars-per-day cost excluding the pumping.

ADJUSTMENT TO 1961

Wheeler[39] estimates operating costs for typical California plants as follows:

	$/day	
Electricity for auxiliaries		
Filter charge pumps, 7-1/2 HP	1.35	
Injection charge pump, 1-1/2 HP	0.24	
Mixer on slurry tank, 1/3 HP	0.06	
Phosphate pump, 1/4 HP	0.05	
Cl_2 heater,	0.20	
Lights	0.05	
Total, auxiliary electricity		$1.95
40 lb Cl_2	$1.90	
5.4 lb polyphosphate	0.92	
100 ppm filteraid	4.75	
Precoat	0.40	
Total chemicals		$7.97
Labor, 2 hr at $2.50		5.00
Total direct costs		$14.92

Based on the above relative proportions for 1952 costs, there was developed a composite cost index. For the electric energy component the average industrial price to large users was used (which incidentally has not varied significantly from 1 cent per kilowatt-hour over the years of interest and probably is a truer figure to use in cost estimates than the 0.5 cent per kilowatt-hour used in this study for consistency with Reference 40. For the labor costs were used the average hourly earnings for non-supervisory workers in petroleum and natural-gas production compiled by the Bureau of Labor Statistics. For the chemicals component was used the Index of Wholesale Prices of Industrial Chemicals of the Bureau of Labor Statistics.[9] The 1952 costs in the three categories were adjusted for each year and from this a composite cost index (1947-1949 = 100) was developed.

Selected values of the index are as follows:
Labor, auxiliary electricity, and chemicals, California plants.

Index 1947-49 = 100

1944	84.3
1948	100.8
1952	121.0
1956	127.6
1960	136.4
1961	136.7

By using these index values, the current year's values for costs per day excluding pumping as computed were adjusted to 1961 with ultimate results as shown in Table 15.

Table 15. COST OF CONDITIONING FOR INJECTION

Plant	Date	Thousand gpd	1961 cost $/1,000 gal, ex pumping
1	1948	246	0.160
2	51	6.8	0.490
3	52	2.52	0.530
7	50	25.2	0.161
8	52	162	0.415
12	47	177	0.555
13	44	33.6	0.710
14	48	16.8	0.206
15	50	7.35	0.192
17	50	84.0	0.126
18	47	566	0.089
est	1952	126	0.121

When plotted on log-log paper these points show considerable scatter. Three plants have exceptionally high costs, but the other eight define a reasonably satisfactory trend line for unit costs as a function of capability. In view of the operating cost breakdown of typical California plants there seems to be no reason why electrical energy for auxiliaries or chemicals should be anything other than proportional to the daily volume. These, with a slight adjustment for the small cost index difference between 1952 and 1961, amount to $0.668 per thousand gallons. From the trend curve for chemicals, electricity, and labor was subtracted this unit cost of chemicals and electricity, which left the labor component. The labor costs developed in this way were read as follows:

Thousand gpd	1	10	30	100	420	500	2000
Residual costs = Labor $/1,000 gal	0.88	0.18	0.094	0.053	0.0265	0.023	(0.023)

The data for labor application at the East Texas Salt Water Disposal Company are quite uncertain. Three different figures are obtained by three different methods of computation: (1) Labor costs for plant and well operation, maintenance, and overhead;[38] (2) number of employees less those in supervision, engineering, G and A, and repair gangs;[34] and (3) an on-the-spot determination that one man per shift operates five plants.[34] The numbers for (3) are midway between the other two at 0.488 man hours per thousand barrels, which at prevailing direct wage rates of $2.84 an hour amounts to $0.033 per thousand gallons. This is about 25 percent higher than the residual labor curve for the California plants and is in the proper direction since the East Texas operation with chemical flocculation is somewhat more complicated. It will be assumed, therefore, that labor costs at any capability for an East Texas type of plant would be 25 percent above that developed for the California plants.

COST OF CHEMICALS

In the East Texas operation the chemicals costs, lime, alum, and chlorine, were $0.01025 per thousand gallons in 1956[38] and $0.01225 per thousand gallons in 1961.[34] We take an average of $0.011. The chemicals cost for the California type has already been developed and is $0.0513 per thousand gallons.

GENERAL, ADMINISTRATIVE, AND FIXED COSTS

General and administrative costs of the conditioning operation are taken as 50 percent of the labor cost. Fixed costs on the investment are taken the same as for the well and pump, namely $\frac{0.258}{1000}$ x capital costs = daily fixed cost.

SUMMARY: COSTS OF CONDITIONING

The data developed above are summarized in Table 16, and shown in Figure 12.

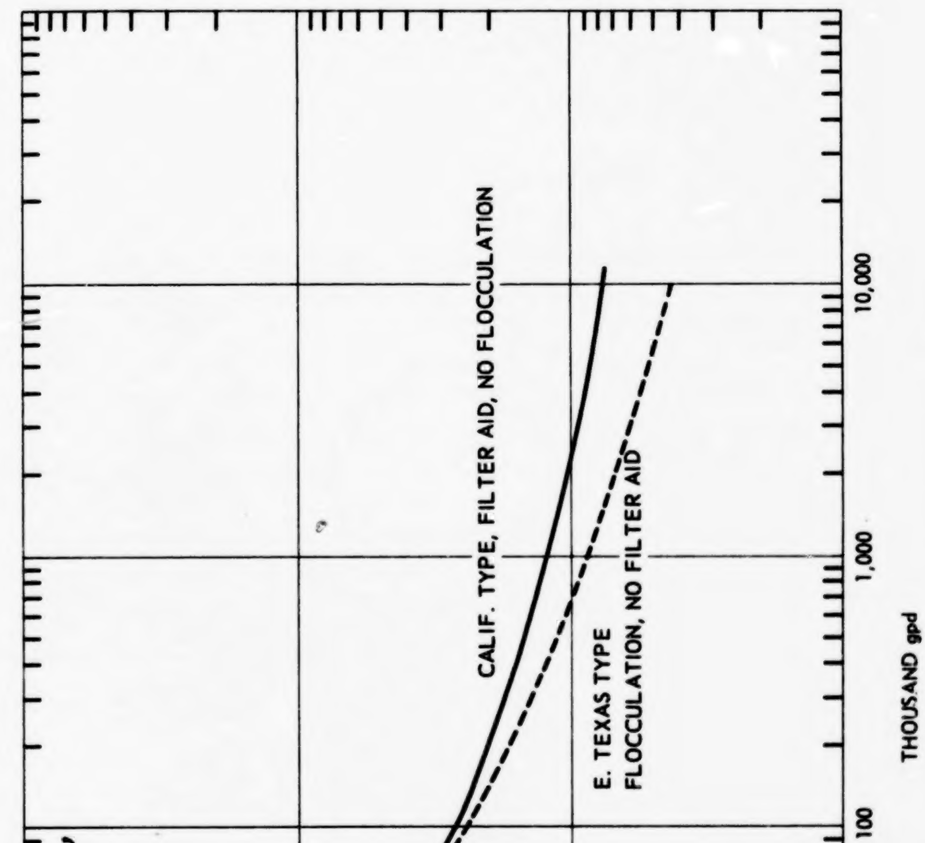

Figure 12. Conditioning costs correlated (conditioning water for injection).

It is seen that the two types have roughly the same costs. The East Texas type shows a slightly higher cost in the low capacity because the labor component is of paramount importance there. In the high capacities the California type shows higher costs primarily because the unit chemicals cost is higher, most of this being the filter aid.

Table 16. CONDITIONING COSTS SUMMARIZED

Thousand gpd	1	100	2,000
Plant cost, $	25,000	40,000	56,000
$/gpd	25.0	0.40	0.028
Fixed cost, $/1,000 gal	6.45	0.103	0.00723
Calif. type: filtration with filter aid, Cl_2, phosphate			
Repairs, $/1,000 gal	1.78	0.0228	0.0020
Labor, $/1,000 gal	0.88	0.053	0.023
Chemicals, $/1,000 gal	0.0513	0.0513	0.0513
Auxiliary energy, $/1,000 gal	0.0078	0.0078	0.0078
G and A, $/1,000 gal	0.44	0.0265	0.0115
Total Calif. type, $/1,000 gal	9.61	0.264	0.1028
$/day	9.61	26.4	205.6
E. Texas type: chemical (lime and alum) coagulation, sedimentation, Cl_2			
Repairs, $/1,000 gal	1.78	0.0228	0.0020
Labor, $/1,000 gal	1.10	0.0665	0.0288
Chemicals, $/1,000 gal	0.011	0.011	0.011
Auxiliary energy, $/1,000 gal	0.0078	0.0078	0.0078
G and A, $/1,000 gal	0.555	0.0332	0.0144
Total E. Texas type, $/1,000 gal	9.90	0.244	0.0712
$/day	9.90	24.4	142.4

It is customary in the oil industry to gear the size of the conditioning plant to the capability of the injection well. There is, however, no real reason why the conditioning plant need be so limited, for a number of injection wells could be supplied from a single conditioning plant, which would presumably achieve lower unit costs of conditioning in the larger plant. The 2 million gpd conditioning plant already represents, however, about a fourfold scale up from the largest plant for which data were available, and more detailed cost estimating than here contemplated would be needed to obtain costs at 10 million gpd. Extrapolation to 10,000 gpd suggests 0.075 per 1,000 gallons for the California type and 0.04 per 1,000 gallons for the East Texas type.

In the foregoing it has been assumed that the concentration parameter will have no effect on the conditioning cost. Actually there will be some effect of concentration, but the amount is not calculable. The increased density would increase the electric energy for auxiliaries, at least for that portion concerned with pumping of the liquor itself. Additional material to be removed, especially organic, polymeric material, would no doubt increase the cost of flocculation chemicals and decrease the length of filter runs. A greater load on sedimentation basins would increase the number of cleanouts per year.

Correlation Of Costs

By summing the injection costs from Table 12 and the conditioning costs from page 55 , the total cost of conditioning and injection for the 81 cases represented by three capabilities, three concentrations, three depths, and three pressures is obtained. These summations are shown in Table 17. Figure 13 shows the disposal costs for the three pressures of the 1.187 density case at the three capabilities according to depth of well. Also included in the figure are curves for the 0 psi case at 1. 005 density indicating that the costs for this lower concentration are of the same general order as for the higher. The costs for the 1. 000 density are identical with those for the 1. 005 within the accuracy of our computation. The unit costs vary approximately from $16 to $58 per 1, 000 gallons for 1, 000 gpd capability, from $0. 30 to $0. 90 per 1, 000 gallons for 100, 000 gpd and from $0. 08 to $0. 28 per 1, 000 gallons for 2 million gpd.

The unit investment cost for 1, 000 gpd capability varies from $50 to $215 per gpd. At 100, 000 gpd they range from $0. 70 to $2. 40 per gpd, and at 2 million gpd, from $0. 05 to $0. 33 per gpd.

The effect of standard wellhead pressure on unit disposal costs is nil for 1, 000 gpd. For 100, 000 and 2 million gpd, the unit disposal cost increases with the standard pressure such that the log of the cost is an approximately linear function of the standard pressure. For 100, 000 gpd the slope is such that the cost increase is approximately 4 percent for each 100 psi increase. At 2 million gpd the corresponding slope is 6 to 10 percent, being higher at the shallower depth.

The fixed costs at 1, 000 gpd make up 80 to 95 percent of the total, 47 to 80 percent of the total at 1, 000 gpd, and 16 to 48 percent of the total at 2 million gpd. Standard wellhead

Table 17. COST SUMMARY, CONDITIONING AND INJECTION – 81 CASES (3 CAPABILITIES, 3 CONCENTRATIONS, 3 DEPTHS, 3 PRESSURES)

			1,000 gpd					100,000 gpd					2 million gpd				
					Disposal cost,					Disposal cost,					Disposal cost,		
psi	Depth, thousand ft	Density, g/ml	Contaminants, tons/day	Investment, $/gpd	$/1,000 gal	$/day	Fixed as % of total	Contaminants, tons/day	Investment, $/gpd	$/1,000 gal	$/day	Fixed as % of total	Contaminants, tons/day	Investment, $/gpd	$/1,000 gal	$/day	Fixed as % of total
900	3	1.187	1.48	51.2	16.45	16.45	83.9	148.4	0.716	0.413	41.3	46.8	2,969	0.107	0.173	345.5	16.1
		1.005	0.0377	51.3	16.47	16.47	80.6	3.77	0.713	0.424	42.4	"	75.4	0.113	0.180	361.1	"
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	7	1.187	1.48	94.6	27.63	27.63	88.4	148.4	1.194	0.523	52.3	59.4	2,969	0.150	0.180	361.1	22.1
		1.005	0.0377	94.9	27.71	27.71	"	3.77	1.155	0.563	56.3	"	75.4	0.175	0.217	436.2	20.7
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	12	1.187	1.48	212.7	58.01	58.01	94.3	148.4	2.38	0.829	82.9	73.5	2,969	0.294	0.209	151.7	36.2
		1.005	0.0377	213.2	58.41	58.41	94.5	3.77	2.40	0.898	89.8	"	75.4	0.331	0.283	170.9	30.1
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
260	3	1.187	1.48	49.4	15.93	15.93	80.0	148.4	0.660	0.343	34.3	49.8	2,969	0.0648	0.0990	198.1	16.9
		1.005	0.0377	50.9	16.33	16.33	80.4	3.77	"	0.357	35.7	"	75.4	0.0809	0.1199	239.7	17.5
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	7	1.187	1.48	92.9	27.11	27.11	88.5	148.4	1.156	0.454	45.4	66.4	2,969	0.1313	0.1072	214.4	31.6
		1.005	0.0377	94.5	27.59	27.59	"	3.77	1.114	0.500	50.0	"	75.4	0.1450	0.1581	316.3	23.6
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	12	1.187	1.48	209.9	57.41	57.41	92.9	148.4	2.34	0.753	75.3	80.1	2,969	0.2562	0.1376	275.3	48.0
		1.005	0.0377	213.0	57.11	57.11	96.0	3.77	2.376	0.758	75.8	"	75.4	0.3007	0.2230	445.9	34.8
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
0	3	1.187	1.48	48.2	15.84	15.84	80.0	148.4	0.643	0.314	31.4	52.9	2,969	0.0522	0.0789	155.9	17.3
		1.005	0.0377	49.4	15.92	15.92	80.2	3.77	0.656	0.335	33.5	"	75.4	0.0644	0.0943	188.6	17.6
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	7	1.187	1.48	91.6	26.81	26.81	88.3	148.4	1.080	0.428	42.8	65.0	2,969	0.0996	0.0907	181.5	28.2
		1.005	0.0377	93.0	27.14	27.14	88.4	3.77	1.107	0.477	47.7	"	75.4	0.1374	0.1315	262.9	26.9
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"
	12	1.187	1.48	209.9	57.41	57.41	93.0	148.4	2.25	0.735	73.5	79.5	2,969	0.2149	0.1214	242.7	45.6
		1.005	0.0377	212.8	58.16	58.16	94.3	3.77	2.37	0.815	81.5	"	75.4	0.2562	0.2042	408.5	32.1
		1.000	0.00125	"	"	"	"	0.125	"	"	"	"	2.50	"	"	"	"

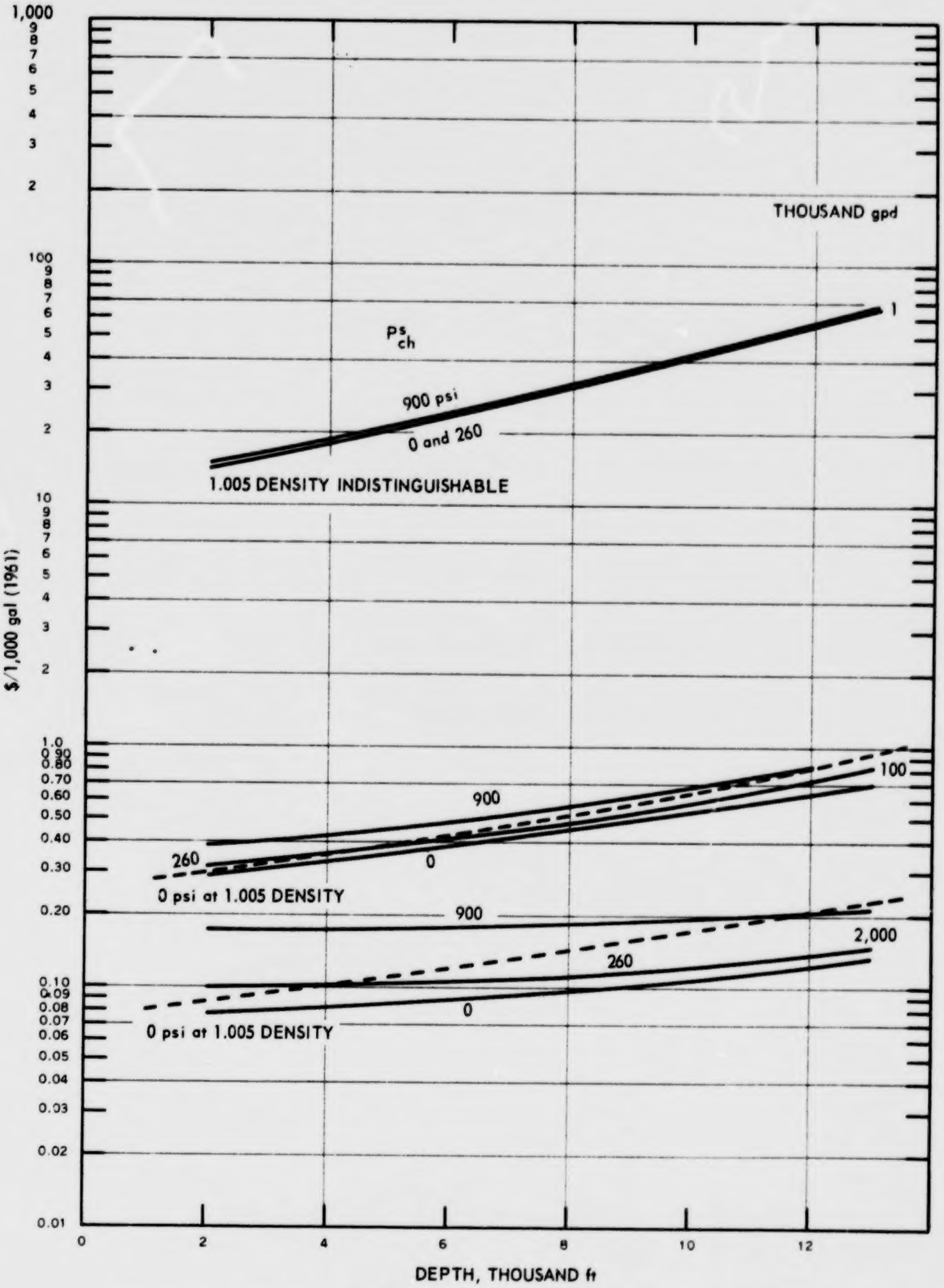

Figure 13. Cost of conditioning and injecting (fluid density 1.187).

pressure has only a small effect on this percentage. Where percentage is low it signifies that actual costs per thousand gallons is sensitive to load factor, that is, operating rate as compared with design capability. Thus, at 2 million gpd and 3,000 feet, daily disposal costs will be almost proportional to actual rate, decreasing as actual rate is decreased. On the other hand, at 100,000 gpd and 12,000 feet, especially at low standard pressures, the daily cost will be almost independent of actual rate since 93 percent of the costs are fixed costs. This means that unit costs will increase hyperbolically as actual rate decreases below the design capability.

COMPARISON WITH WET OXIDATION

A correlation according to capability is shown in Figure 14 where a comparison is made with unit costs of wet oxidation. It is seen that the unit costs of disposal by injection to underground formations are well below those for ultimate disposal of the organics by wet oxidation except at very low capabilities. At 1,000 gpd the unit costs of disposal by injection approach those for wet oxidation and exceed them for a 12,000-foot depth.

Also plotted for comparison (as the lowermost, dashed curve) is the 7,000-foot case, without conditioning, to show the contribution of conditioning to the disposal costs. This indicates incidentally that any reasonable means that might be taken in the waste treatment processes themselves to produce a conditioned waste should be utilized, for the cost of conditioning is a significant portion of the cost of disposal by injection. It should be recalled that the wet-oxidation method handles only the organic materials, and subsequent to wet oxidation, there must be steps to handle the residual organics as well as the untouched inorganic contaminants.

Also plotted (as the uppermost, dashed curve) is the 12,000-foot case at 9,000 ppm, to show the effect of concentration, which is minor.

In Figure 15 the data for economic choice between injection and wet oxidation are provided. This Figure corresponds with Figure 8 in AWTR-3 (999-WP-3), except that the axes have been interchanged and the units are tons of contaminants rather than tons of organics.

The black lines in the Figure refer to ultimate disposal by injection for 7,000 feet and 900 psi. The red lines superposed refer to wet oxidation and are drawn from Figure 8 of AWTR-3. In directing attention first to the black, approximately horizontal

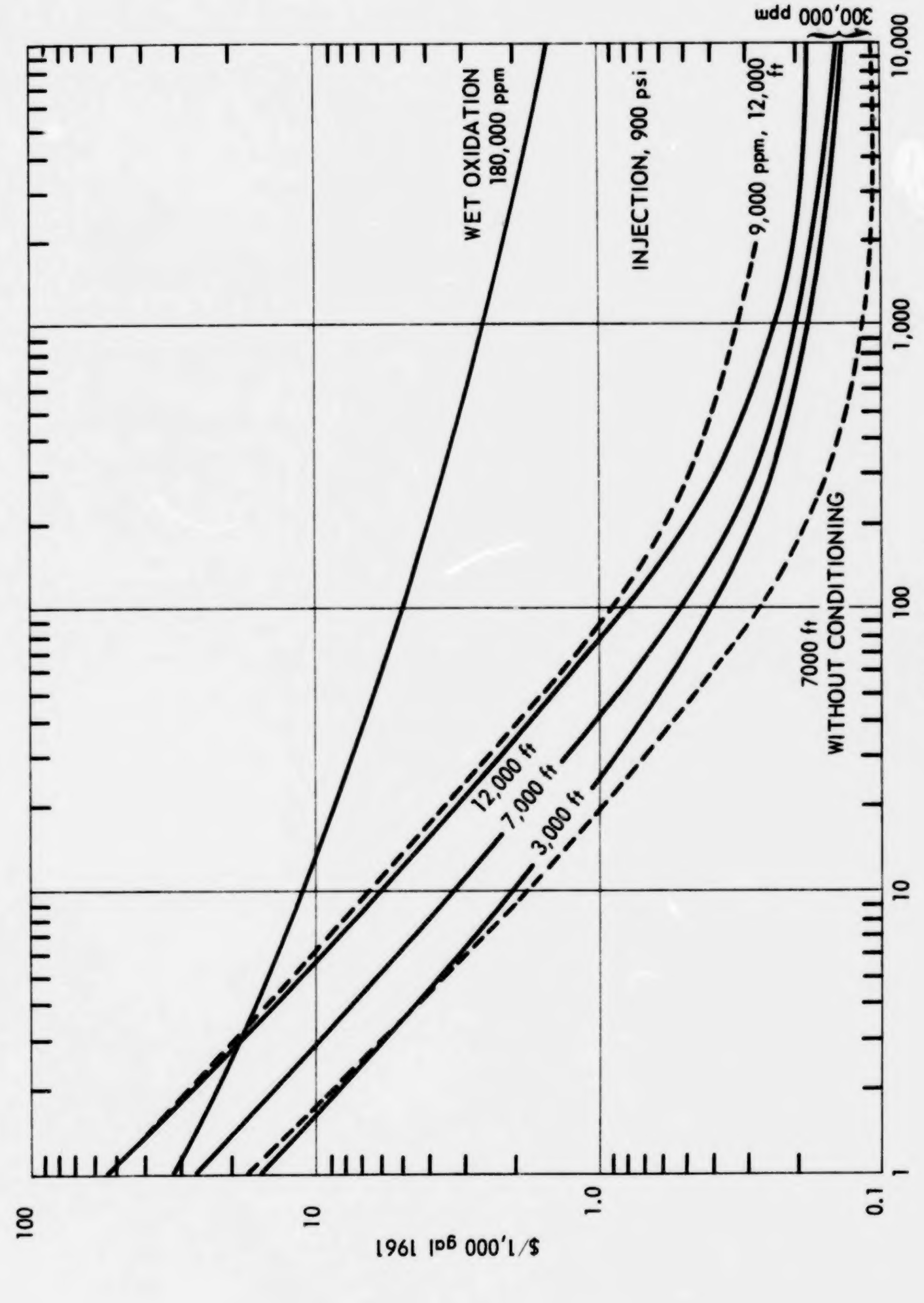

Figure 14. Unit disposal costs compared.

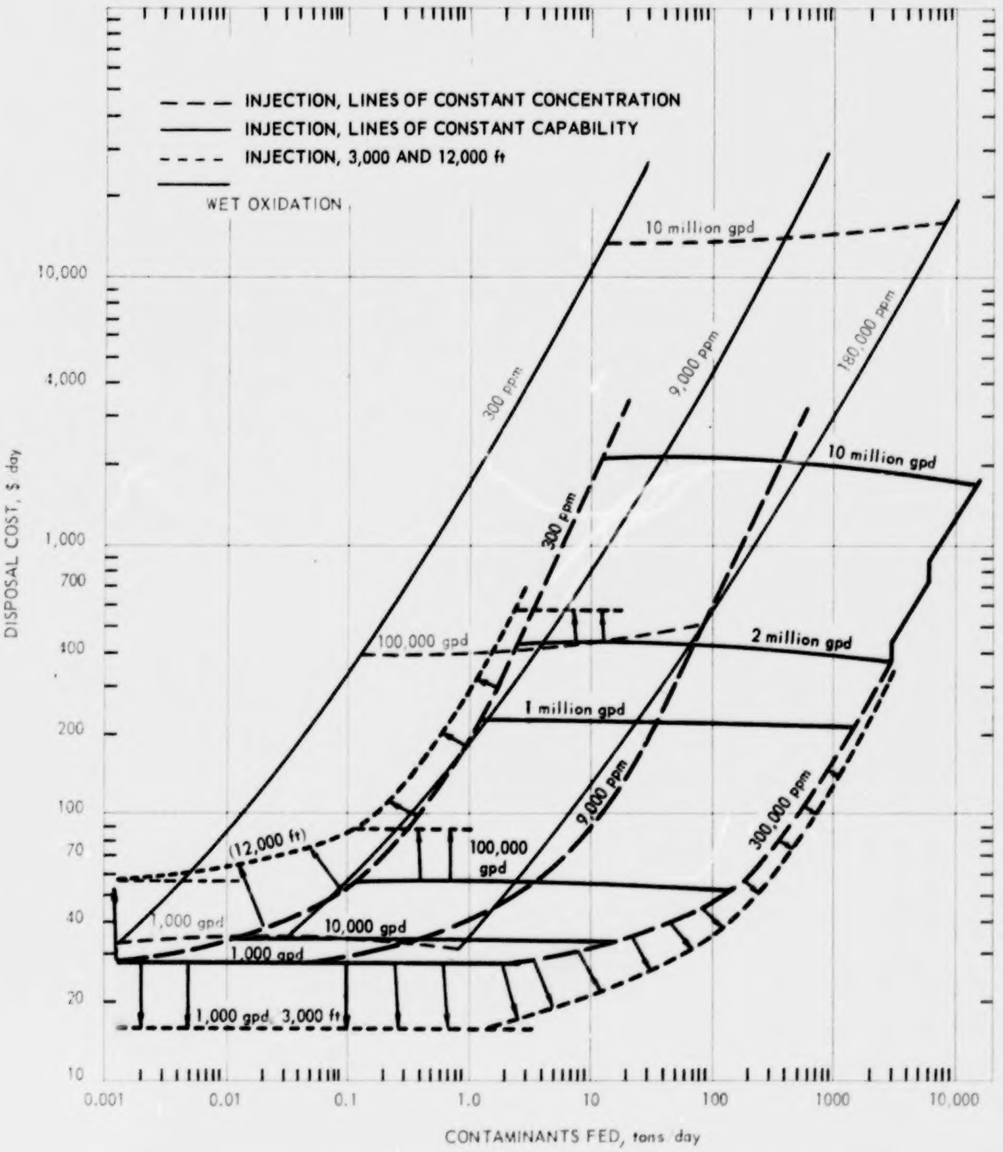

Figure 15. Economic choice, injection and wet oxidation (900 psi, 7000 ft).

lines, it is seen that the daily disposal costs are practically independent of the tons per day of solids disposed and are almost totally a function of the volume disposed; 1,000 gpd, for example, will cost approximately \$27 per day for disposal regardless of its concentration, while 100,000 gpd will cost approximately \$55 per day, and 2 million gpd approximately \$400 per day, also practically independent of their concentrations.

The black lines curving up to the upper right are lines of equal concentration. At the termination of the 300,000 ppm line is a series of step-like curves. These represent replication of the 2 million gpd injection plant, whereby for example, a 5,938-tons-per-day plant would be composed of two 2,969-tons-per-day plants at the same unit (per 1,000 gal) cost. The step is not a right-angled step because only a portion of the replicate costs are fixed costs, and these are represented by the vertical portion of the step. The sloping portion of the step represents the added variable costs, which are proportional to the rate. Actually the entire series of curves would have this discontinuous, step-like, fine structure, but the steps are dispensed with in the rest of the curve since they are also in the 9,000 and the 300 ppm curves.

The dashed, black, horizontal line lowermost in the Figure represents costs for 1,000 gpd disposal at a 3,000-foot depth rather than the 7,000 for the main Figure. The arrows indicate displacement of the 1,000 gpd line downward. Similarly illustrated on the lowermost line curving to the upper right is the displacement from 7,000 feet to 3,000 feet of the 300,000 ppm line.

The 300 ppm curve is also shown, by arrows, as displaced to 12,000 feet. The horizontal extensions from points on this curve represent the corresponding displacement of the 1,000, the 100,000, and the 2 million gpd curves. Thus by looking at the displacements, for example, of the 1,000 gpd curve (at the extreme left of the diagram), one may visualize the effect of depth on daily disposal costs.

The red network shows the data for wet oxidation transposed from Figure 8, AWTR-3. It should be noted that the axis in AWTR-3 is tons per day of organics fed while that of Figure 14 is tons per day of contaminants fed. A comparison of the horizontal, constant-rate lines shows the superiority costwise of disposal by injection over disposal by wet oxidation. For example, for the same daily cost of about \$400 per day, one may dispose of 2 million gpd by injection but only 100,000 gpd by wet oxidation. Even at a 12,000-foot depth this superiority is not much altered.

At 1,000 gpd, however, the costs of injection are near the costs of wet oxidation, at 7,000 feet. At 3,000 feet, injection costs only about half as much as wet oxidation; and at 12,000 feet about 75 percent more than wet oxidation. Actually the break-even point between wet oxidation and injection at 1,000 gpd would be represented by a formation about 8,500 feet deep. Thus, if only the organic matter were concerned, if nonultimate disposal such as discharge to streams were permissible for the wet oxidation residue, and if disposal wells would have to be more than 8,500 feet deep, the economic choice would be for wet oxidation.

It will be recalled that the 1,000 gpd well is designed with 2-7/8-inch casing as the smallest size that would be set, and is, therefore, much oversize for the flow. The pressure drop is so small that the horsepower requirements are quite negligible, and this means that the actual flow could be increased many times before the pressure drop becomes large enough to create significant horsepower requirements compared to the well costs. Accordingly, so far as injection is concerned, the daily cost would be the same for 2,000, 3,000, or even 4,000 as it is for 1,000 gpd. The conditioning costs, however, continue to increase with volume and, though they make up about 60 percent of the conditioning and injection costs at 3,000, 7,000, and 12,000 feet, they comprise only about 35 percent and about 17 percent respectively. Accordingly, at least for the deeper wells, the total costs are rather insensitive to capability in the 1,000 to 5,000 gpd range. As a check on this, a special computation was made for 10,000 gpd with results as shown on the Figure. It is seen that for the cost of disposing of 1,000 gpd by wet oxidation, 10,000 gpd could be disposed by injection.

LOGISTICS

The logistics of ultimate disposal is sketched in Figure 16 in which disposal cost in dollars per million gallons of water produced in the advanced treatment is shown as a function of the percent recovery in advanced treatment. The illustrative example taken comprises a community of 60,000 population producing 10 million gpd of secondary effluent containing 300 ppm of total contaminants (100 organic and 200 inorganic). The feed to the advanced-treatment plant from this community would contain 12.5 tons per day of total contaminants. Table 18 shows what disposal of the advanced-treatment waste would cost per million gallons of water produced in the advanced-treatment plant.

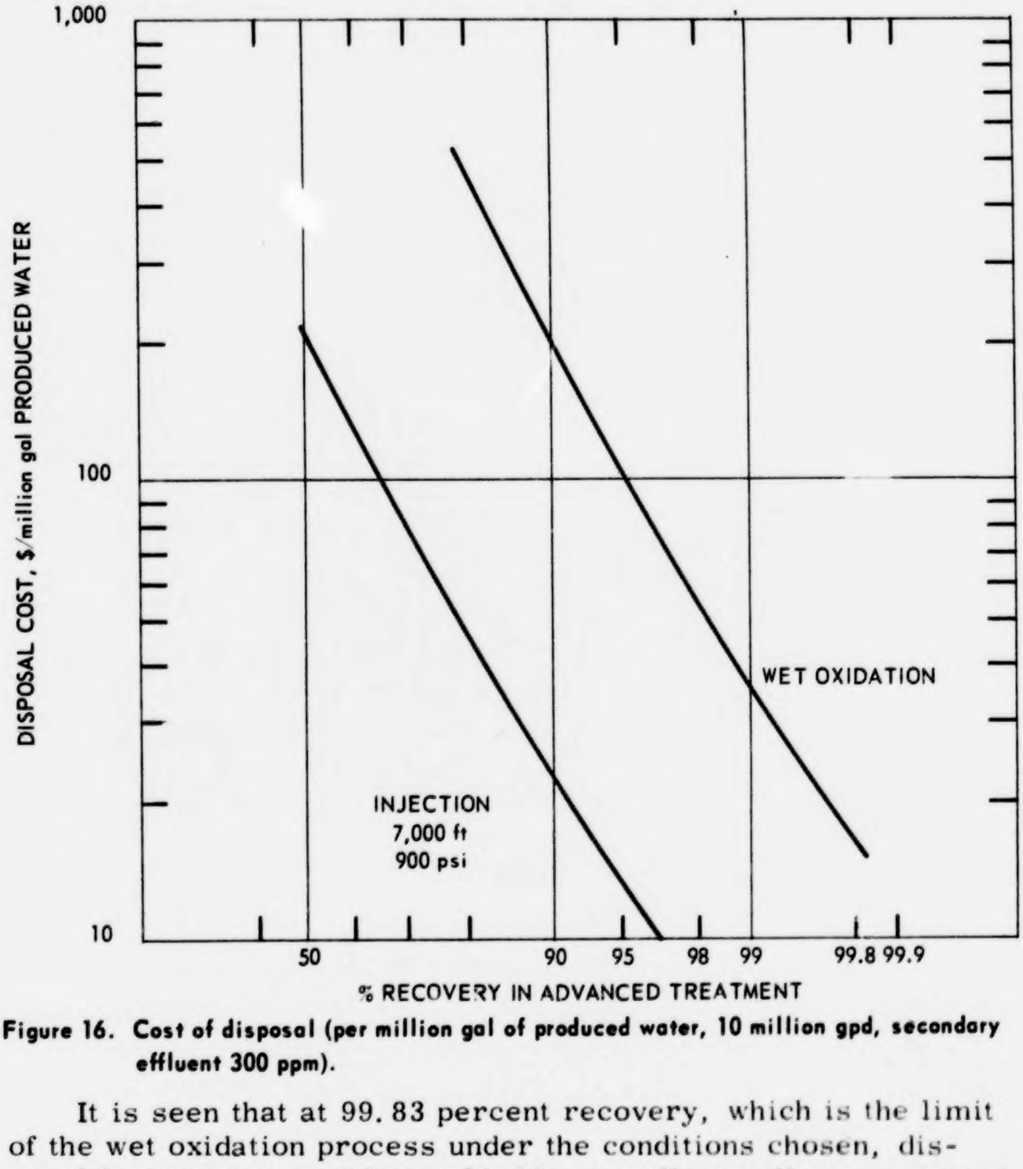

Figure 16. Cost of disposal (per million gal of produced water, 10 million gpd, secondary effluent 300 ppm).

It is seen that at 99.83 percent recovery, which is the limit of the wet oxidation process under the conditions chosen, disposal by injection would cost $3.80 per million gallons compared with $15.50 per million gallons for wet oxidation. At a slightly lower recovery 96.67 percent wet oxidation would cost $91, while injection would cost only $10.50 per million gallons of produced water. At 80 percent recovery injection disposal cost has risen to only $50 compared with $538 for wet oxidation.

Similar analyses can be made for other injection conditions and other community examples by using the data presented in this and in the wet-oxidation report (AWTR-3).

It is apparent still that for injection it will be necessary to run the advanced treatment to high recoveries to realize reasonably low disposal costs. With injection, however, the necessary recoveries are much lower than for wet oxidation; 96.67 percent recovery, would incur $0.01 per thousand gallons of produced water for disposal costs, while if \$0.05 per thousand gallons could be taken then recovery would need to be run only to 80 percent. Of course, in the latter case 20 percent of the valuable water product would be irrevocably lost to utilization. This, however, is only one of a number of factors other than disposal costs alone that must be taken into account in any logistical analysis of advanced treatment.

Table 18. UNIT DISPOSAL COST ACCORDING TO PERCENT RECOVERY IN ADVANCED TREATMENT

Recovery of product water in advanced treatment, %	Total contaminants concn of adv treatment waste, ppm	Disposal cost, \$/million gal produced water, by wet oxidation	Disposal cost, \$/million gal produced water, by injection[a]
99.90	300,000		3.20
99.83	180,000	15.5	3.80
96.67	9,000	91.1	10.5
80.0	1,500	538	50.0
50.0	600		19.6

[a] At 7,000 feet, 900 psi.

The Capacity Of Underground Storage

PORE VOLUME CAPACITY

Measured by everyday standards the pore volume of storage space available underground is enormous. On the assumption that the injected fluid moves out from the well in a cylinder and fills the available porosity, the radius reached at any time will be:

$$r_e = 0.0236 \times \left[\frac{Q}{h} \times \frac{y}{p}\right]^{\frac{1}{2}} \qquad (6)$$

where:

r_e = radius to which injected fluid will reach, miles
y = years
p = porosity, ft^3/ft^3
h = height of formation, ft, assumed constant with distance
Q = thousand gpd

Under typical reservoir conditions with porosity about 25 percent, when $\frac{Q}{h} = 1$, that is, with 20 feet of face and 20,000 gpd capability, then in 100 years the front of the injected fluid will have traveled only about one-half mile, and in 2,500 years it will have traveled less than 2.5 miles. Under the more extreme conditions in putting 2 million gpd into the same 20 feet of face, in 100 years it will have traveled 4.75 miles, and in 2,500 years, 23 miles.

It may be concluded that under reasonable conditions one may expect to inject into the far future so far as pore volume capacity is concerned.

PRESSURE CAPACITY

There is an important difference between salt-water disposal in an operating oil field and waste-water disposal from advanced-treatment plants. The salt water returned to an oil formation or pumped into it for pressurizing fills in the pore spaces that are vacated by the original reservoir fluid. Typically 1 to 5 barrels of water would be removed from the producing wells with each barrel of oil, and the water, but not the oil, is returned to the formation. In the 5:1 ratio 5 barrels of water are injected into the space from which 6 barrels have been removed. This mechanism is not difficult to visualize.

In disposal of advanced-treatment wastes, however, the usual attempt is to inject water into a formation when nothing is being removed and the formation is completely isolated from surface contact.

An exception to this might occur if the original water supply were from a nonrenewable ground water reservoir. In this case it is conceivable that the waste from advanced treatment might actually be used to repressure the ground water formation, which would permit more economical production of ground water, while it lasted. In the great majority of cases, however, this could not be done, for the ground water source usually consists of a renewable reservoir, and since we are talking in terms of scores of hundreds of years, wastes should not be injected into it for repressuring. For other than this exception it is unclear just what is going to happen to the advanced-treatment wastes injected underground.

While the liquid front, if there were such, would advance quite slowly, as shown above, the pressure wave due to the injection would be far in advance of it. Hence, the Theis nonequilibrium relationship describing the withdrawal of ground water from a confined aquifer may be used, in reverse, to predict the pressure-distance-time relationship in an injection situation in which the Theis mechanism is followed. de Laguna and Blomeke[41] have done this for aquifers over a range of transmissivities (i. e. , permeabilities). The lowest transmissivity of 100 gpd per foot is judged to correspond to permeabilities to be expected in deep-well injection formations. Thus at a transmissivity of 100, if the formation were 20 feet thick, the permeability would be 272 millidarcys; if it were 100 feet thick, 55 millidarcys. Such permeabilities are typical of petroleum field injection practice, though some fields enjoy permeabilities as high as 2, 500 millidarcys. The calculations of the Reference show that, for the 100 transmissivity, the pressure front would reach 1 mile in about a year at an injection rate of 144, 000 gpd, but this time is independent of actual injection rate. At the wellhead, however, the pressure would increase by 700 psi in 10 days and by 900 psi in 1 year, and this pressure increase is proportional to the injection rate. These computations refer to an aquifer of infinite areal extent, which amounts to a radius, at the 1, 440 gpd injection rate, of about 1 mile over a period of 1 year and about 100 miles over a period of 350 years.

The Theis mechanism, and thus the de Laguna and Blomeke mechanism, involves the acceptance of injected fluids by compression of the fluid already in the formation and compression of the formation rock itself. Where large areas and long time are involved, additional mechanisms, which may increase or decrease with pressure, must be considered. A number of these mechanisms are actually used in predicting the behavior of petroleum reservoirs in which fluids are produced from rather than injected into confined formations. In all there are about a dozen conceivable mechanisms by which formations might accept injected fluids. These will have to be explored before a clear understanding is reached on the pressure behavior of confined formations on prolonged injection of waste fluids.

Areas For Further Investigation

A number of areas remain for further investigation, some representing deficiencies in the data available for the present study, others comprising the next stages that should be undertaken in an appraisal of the general applicability of injection for ultimate disposal of advanced-treatment wastes.

DEFICIENCIES IN PRESENT STUDY

One of the major deficiencies of the present study lies in the range of well component costs developed largely through the ranges in contractor costs and mud costs. An attempt was made to show how much this might alter the investment costs for average wells, but it was not possible to carry these maximum and minimum ranges throughout the work.

A second item for strengthening the present study would involve a more thorough investigation of the effect of hole diameter on costs of well components, especially on contractor costs and mud costs. The basic data used for this purpose in the present study were of necessity very sketchy. It is conceivable that the Joint Associations might be asked to include questions relative to diameter in future surveys. This would allow a firmer extrapolation from typical oil and gas well diameters to the much larger and much smaller diameters required for waste disposal.

The present study uses a somewhat arbitrary method of selecting the pressure parameters, which is essentially in terms of bottom hole dynamic pressure, that is, the sum of the reservoir pressure and the pressure-differential driving force, to overcome the resistance of the formation. This has two arbitrary effects that should be eliminated in a future study. First it fixes the formation permeability as a function of reservoir pressure, or vice versa. In actual formations, however, these two parameters are independent variables. Second, in the cases chosen it arbitrarily ties bottom hole dynamic pressure to the chosen flow rate. For example, a 100,000 gpd well with a standard wellhead pressure of 260 psi in the sense taken in this study would not have a standard pressure of 260 psi if the flow were 2 million gpd or 1,000 gpd, for a portion of the 260 psi consists of the driving force to overcome formation resistance, which is proportional to flow. As described in the text, the reason for not doing this in the present study was that it would introduce a still further independent parameter, namely formation permeability - a parameter that has a tremendous range of variation in nature. In practice, however, injection formations are described in terms of their permeabilities, and the improvement suggested here would allow a determination of what range of permeabilities are within economic reason.

It is likely that the costs of Triplex pumps used in this report are too high in the low-horsepower regions. The costs were developed by coupling a Triplex pump of 50 horsepower maximum capacity with electric motors of continuously varying horsepower down to the 1 horsepower size. The opportunity was not taken to investigate this further in the present study, but it seems likely that smaller high-pressure pumps would be available for use, say at least below 10 horsepower. Casting some doubt on this supposition, however, is the fact that the slope of the Triplex line approximates the slope of the centrifugal pump line, which is taken from published literature and no doubt uses progressively smaller pumps as well as motors at the lower horsepowers. The subject remains for a deeper investigation.

The present study computes 81 different combinations of the four parameters, but, owing to scope limitations, could only discuss (e. g., compare with other ultimate-disposal methods) a few of these selected as typical. This is not, however, to be considered a deficiency of the study, for all the data are presented for making analogous comparisons with the other 70-odd cases or interpolations among them.

Conditioning-plant-operating component costs are not well documented in the literature as a function of capability. When this study was planned it was guessed that conditioning costs would be small compared to injection costs, and relatively large errors in conditioning cost estimation could, therefore, be tolerated. Conditioning costs, even the simple type of conditioning common in the oil fields, turn out, however, to be not small relative to injection costs, and so hindsight allows us to wish for greater firmness and accuracy in estimating conditioning costs. Required would be a rather extensive and thorough study of conditioning plant operations, in which a foreseeable complication is the rather loose accounting terminology that is common because the accounting systems are designed for purposes other than our present purpose.

FUTURE STUDIES

Injection as a method of ultimate disposal appears to involve low cost. If, when compared with the other methods to be studied in this series and possibly with others not covered by the planned series, the costs and physical magnitudes still appear encouraging, then further, more detailed studies on injection should be undertaken. Some of these are outlined in the following paragraphs.

A nationwide study should be made concerning the existence and accessibility of underground formations suitable for ultimate disposal. Particularly important should be the permeability or transmissivity, the porosity or storage coefficient, the depth, the extent to which the formation is sealed off from other formations, and the areal extent of the proposed injection formation. This study would involve the disciplines of geology, particularly petroleum geology, and reservoir engineering. Once these parameters are known one may "plug them in" to the results of the present study and thus arrive at costs characteristic of the particular geographic regions in which the actual injection formations exist. One might in this way begin to form a pattern of costs of ultimate disposal by injection according to geographical region. The costs might change radically and would change abruptly at the boundaries of the actual existing injection formations. The geographical variation in well costs, only briefly alluded to in the present study, and a similar probable variation in conditioning plant costs should be taken into consideration in such a geographical study. To illustrate: All of the well component costs used in the present study refer to conditions in existing petroleum production regions where oil field technology and oil field services are readily available close to their bases of operations. The construction of a well in a region remote from these bases of operations would, however, be more expensive and possibly significantly so.

One of the most important future studies concerns the pressure behavior of the receiving formation. The great bulk of our knowledge of the pressure behavior of underground formations on injection comes from oil field practice. In that practice injection is made to formations from which formation fluids have been, or are being taken. Ultimate disposal of liquid wastes involves, however, injections to formations from which there is no volume relief of this kind. Such industrial disposal wells as have been operated under these conditions are usually injecting relatively small daily volumes, and this has been done over a period of years, or at most, decades. Ultimate disposal for advanced waste treatment, however, must plan for injection of large volumes and presumably over centuries rather than decades. Theoretical and practical study is required to predict the pressure behavior of such injection systems and to assure that pressure buildup will not make the system uneconomical in a relatively short time. This study is entirely aside from the specialized and particularized study of whether a particular formation will maintain its seal over a long period of years.

Since the cost of even simple treatment is relatively high every effort should be made within economic bounds to accomplish as much conditioning as possible within the advanced waste treatment plant and process itself. To a certain extent of course the logistics of advanced waste treatment planning will dictate the type of waste to be produced, but within this framework studies should be made, for example, to see whether filtration could not be more cheaply accomplished in the advanced treatment plant than in a separate conditioning plant.

Present technological restrictions on the construction and maintenance of wells smaller than 2-7/8 inches diameter limit true economic sizing of these wells to capabilities of about 100,000 gpd. Wells of the smallest size now conventionally drilled (namely 2-7/8-inch casing and 6-3/4-inch hole) are oversized for capabilities lower than this. If there is to be extensive utilization of disposal by injection of capabilities of say 50,000 and 10,000 gpd, then some investigation should be encouraged to develop techniques whereby smaller diameter wells could be constructed and operated. In the case of capabilities as small as 1,000 gpd, it appears possible that other methods (for instance hauling away in tank cars) might be cheaper than injection. To the extent that this is the case there would be no need for stretching the technology toward smaller diameter wells.

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ULTIMATE DISPOSAL
BY PLACEMENT
IN UNDERGROUND CAVITIES

Part 2.

PLACEMENT IN UNDERGROUND CAVITIES

Summary

In some of the processes for the production of water being investigated under the Advanced Waste Treatment Research Program of the U.S. Public Health Service, water is extracted from the raw material or contaminants are removed therefrom to yield the ultimate product and a waste stream consisting of the contaminants and possibly some of the reagents in a more or less concentrated form. A preliminary process design and cost estimate were made for ultimate disposal of these liquid wastes by placement in underground cavities. The process parameters were daily volumes taken as 1,000, 100,000, and 10 million gpd. The concentration of waste is not a parameter affecting the costs.

Disposal to created sal cavities, which is the major method of creating underground storage space for present industrial uses, has been shown to be inapplicable to advanced-treatment waste because under all conditions the difficulties of disposing of the salt waste from the cavity would be greater than those of disposing of the advanced-treatment waste itself.

Underground storage has been shown to be an operable industrial practice. In 1956, for example, 244 cavities were in use for storage, mostly of hydrocarbons. In 1960 there were 29 mined cavities in use other than those in salt. They are successful because for the materials stored the cost of aboveground storage is much greater than the cost of underground storage.

Costs were developed for mining the optimum size caverns for ultimate disposal of advanced-treatment wastes at each of the three capabilities. For the largest capability, 10 million gpd, the scaleup factor from the largest existing mined cavity was 130-fold, and it would be necessary to have under construction at any given time approximately 250 caverns to provide enough storage space. The fixed costs for the disposal at 1,000, 100,000, and 10 million gpd were $243, $84, and $72 per thousand gallons respectively. These did not include the cost of hauling the spoil a short distance to a dump, nor the rental cost of the dump land,

both of which are but a small percentage of the fixed costs. The produced spoil might be utilized to replace some of the stone and construction sand and gravel now produced, the annual production being sufficient for a large number of ultimate disposal plants. It is, however, unlikely that the spoil could substitute for any but the low-grade uses, which are rather small in percentage. Furthermore, even at a substantial credit per ton for spoil, the cost of the disposal would be lowered by only 7 to 14 percent, which is inconsequential.

The cost of cavities constructed by nuclear blasting decreases sharply with volume such that the disposal costs (fixed only) for 1,000, 100,000, and 10 million gpd would be $139, $2.69 and $0.269 per thousand gallons, respectively. In the larger sizes the scaleup from the prototype nuclear blast is 1,400-fold, but the limiting factor is actually the burial depth of the explosive necessary to contain the created cavity. The feasibility of such large cavities must at present be considered highly speculative, but further data will be forthcoming from new underground nuclear tests.

In considering the possibility of utilizing existing underground cavities, it was shown that there are created by mineral production in the United States cavities of about 800 million gpd capacity, of which 152 million gpd are underground and of which in turn about 116 million gpd are from underground mining of bituminous coal and lignite, and 6 million gpd from salt production. The necessity for investigation of the geographical distribution of these cavities and of their individual suitability for ultimate disposal is pointed out. The greatest potentialities exist in the bituminous coal cavities since this distribution follows somewhat the national distribution of waste production. Use of other cavities that follow ore occurrence would bring about serious problems of transportation to the cavity sites. The emphasis upon salt cavity storage for radioactive wastes cannot be translated into optimism for that type of disposal of advanced-treatment waste, for the problems differ in a number of parameters by several orders of magnitude.

Disposal to nuclear cavities is under all conditions more expensive than disposal by injection. At very high capabilities, however, it approaches the cost of injection (where nuclear cavity costs are highly speculative), and remains superior to wet oxidation and to incineration at intermediate capabilities. At very low capabilities the costs are greater than for wet oxidation or incineration; 100,000 gpd for instance, could be disposed of by injection for the cost of disposing of 1,000 gpd by nuclear cavity storage, and 1 million gpd could be disposed of by injection for less than the cost of disposing of 100,000 gpd in nuclear cavities.

As an example the daily cost of storage is computed for advanced-treatment processes for a community of 60,000 population producing 10 million gpd of a 300 ppm feed to the advanced-treatment process. The cost of disposal to nuclear cavities would be $111 per million gallons of water produced in the advanced-treatment plant at a recovery of 80 percent and $43 at a recovery of 96.67 percent. At 99.9 percent recovery, which would produce a waste of the upper limiting concentration, the cost for disposal to nuclear cavities would be $17.4 per million gallons, which compares with $3.20 per million gallons by injection (at 7,000 feet and 900 psi).

Logistics Of Salt Cavity Disposal

As will be shown later, the bulk of underground storage experience in the United States consists of storage for petroleum hydrocarbons, and of this the major portion of the total volume comprises cavities in salt domes and salt beds. The cost of constructing these by solution methods is low compared with the cost of mining operations. Moreover, the salt has favorable rock characteristics for containing the stored material, and the vertical height of the cavity can be much larger than with mined cavities. Storage in salt cavities is also a prominent method for ultimate disposal of radioactive wastes.

On the contrary, storage for ultimate disposal of advanced-treatment wastes in salt cavities other than those already existent, that is, in those that have to be created, may be dismissed by the following reasoning and magnitudes.

The density of rock salt is about 130 pounds per cubic foot. The density of saturated NaCl brine of about 25 percent concentration at ambient temperatures is about 1.19 grams per milliliter or about 75 pounds per cubic foot. In each cubic foot of saturated brine there are, therefore, 18.7 pounds of salts. This is the maximum weight of salt that could be contained in 1 cubic foot of advanced-treatment waste. To dispose of this 18.7 pounds of salt in the waste, 130 pounds of rock salt would have to be mined. In other words, the problem of disposing of 18.7 pounds of advanced-treatment-waste salts would be replaced by the problem of disposing of 130 pounds of rock salt whether mined by conventional methods or by solution methods.

SOLUTION MINING

If the 130 pounds were mined by solution methods they would occupy 7 cubic feet in the saturated solution. In disposing of

1 cubic foot of the most concentrated advanced-treatment waste, 7 cubic feet of mining wastes would, therefore, be produced. Thus the problem of ultimate disposal of 1 cubic foot of advanced-treatment waste would be replaced by the problem of disposing of 7 cubic feet of mining waste.

Furthermore, this 7 cubic feet of mining waste would contain 6. 3 cubic feet of water that would have to be either fresh water or, more likely, feed to the advanced-treatment plant (typically secondary sewage effluent). This 6. 3 cubic feet of additional water per cubic foot of waste would constitute an additional requirement on the feed to the over-all process (advanced treatment plus solution mining) and would lower the over-all yield. The relationship is as follows

$$Y' = \frac{Y}{1 + 6.3\ (1 - Y)} \qquad (1)$$

where:

Y = yield of advanced-treatment process (product rate/feed rate, fraction)

Y' = yield from over-all process (product rate/feed rate plus mining water rate, fraction).

The over-all yield falls off much more rapidly than the advanced-treatment yield in the region where these yields are of interest. For example, the following shows some selected points:

Advanced-treatment yield	1.00	0.99	0.90	0.80
Over-all yield	1.00	0.928	0.552	0.354

It appears inevitable, then, that the disposal of the solution mining waste for ultimate disposal of advanced-treatment waste will involve more expense than disposal of the advanced-treatment waste itself.

CONVENTIONAL MINING

The possibility remains that disposal of a solid waste from salt cavities mined by conventional mining techniques might be less expensive than disposal of a liquid waste from advanced treatment. One cubic foot of salt would be mined for disposal for every cubic foot of advanced-treatment waste to be disposed, or approximately 8.7 tons of mine waste for every thousand gallons of advanced-treatment waste to be disposed. The only possible disposal for the mined waste would be hauling it to a remote dump or to the ocean. A corresponding disposal of the advanced-treatment waste would be pipelining it to the ocean.

Data are available on generalized costs of pipelining.[1, 2] That study was only preliminary, but we shall use it now. The data therein may be corrected to Engineering News-Record Construction Cost Index of 850, corresponding approximately to 1961, and adjusted by the short-haul correction found therein. In AWTR-3 (999-WP-3) data are developed for the cost of hauling solid waste by railroad. The data for the Mid-continent region will be used in the present comparison. When this comparison is made for a 100,000 gpd plant, it reveals that to haul the mine waste for any given distance would cost many times as much as to pipeline the original advanced-treatment waste itself. Selected values are shown in Table 1.

Table 1. COST OF HAULING MINE WASTE (1961, VOLUME EQUIVALENT TO 100,000 gpd)

Miles	$/1,000 gal to pipeline	$ to haul corresponding salt mine wastes by railroad	Ratio
1,000	32.7	117.5	3.6
400	13.6	68.7	5.0
100	3.9	34.8	8.9
10	0.56	17.4	31

The conclusion applies to the present data but is subject to some change. The cost of pipelining as computed in the Reference was based on ordinary pipe, whereas any revision of that study would call for corrosion-protected pipe, which would increase the cost of pipelining. Also the railroad freight rate is based on the lowest possible class rate, but it is very likely that if a sizable and regular business develops special commodity rates would be established by the railroads. The commodity rates are significantly lower than class rates. Thus the pipelining costs probably could, in the future, be revised upwards whereas the freighting costs could be revised downwards. Furthermore, as seen in AWTR-3, freighting costs could be considerably reduced where barging is possible, but, since the present series of studies does not include one on competitive hauling methods, this must be left only as a suggestion. In any event the comparison made here is only among the costs of transporting. It must be recognized that, in addition, the mined-salt method of disposal must bear the cost of mining itself, which, as shown later, is at least several tens of dollars per thousand gallons. The above comparison applies for 100,000 gpd of advanced-treatment waste. Pipeline transportation costs for 10 million gpd[2] are about one-tenth of the 100,000 gpd costs, but railroad rates are unchanged, so the same conclusion would apply even more firmly.

At 1,000 gpd, however, the pipeline conveyance costs are about 10 times those at 100,000 gpd.[2] Accordingly, for distances more than some mileage less than 100 miles, it would be cheaper to freight the 8.7 tons of mine waste than to pipeline the equivalent 1,000 gallons of advanced-treatment waste. Indeed, at 1,000 miles, the ratio would be 1/3 instead of the 3.6 in Table 1. At 1,000 gpd, however, it is more likely that tank car freighting of liquid waste would be utilized rather than pipelining, and so this subject calls for investigation.

TANK CAR HAULING

Freight rates for transporting tank cars are approximately the same as those of equivalent service for solids in bulk,[3] but the tank car must be leased from a tank car-leasing corporation according to the following schedule.[4, 5] Welded tank cars lined with corrosion-resistant material would be required. An 8,000-gallon car rents for $120 and a 20,500-gallon car for $200 per month. The freight rate for hauling is paid on the one-way trip and no freight is paid for returning the empties. A rebate of 5.5¢ per mile is, however, applied against the monthly rental charges, being calculated on both legs of the trip. Time involved is 1 day for loading, 1 day for unloading, and movement in transit of approximately 100 miles per day.

For using the above data optimum schedules were worked out for transportation in the 8,000- and 20,500-gallon cars. At all distances for which the comparison was made the 8,000-gallon car was cheaper than the 20,500-gallon car, so all data presented are for the 8,000-gallon car. Under some schedules a few days' on-site storage would be required, but the cost of this was considered negligible and was not computed.

Table 2 shows the results and compares them with the corresponding costs for pipelining 1,000 gpd of original waste and of hauling mine waste of equivalent volume. All freight rates used were for the midcontinent district.

The table shows that, as predicted, for distances more than about 100 miles, it would be cheaper to haul the solid mine waste than to pipeline the liquid advanced-treatment waste. At 1,000 miles, as predicted, the ratio of solid hauling to pipelining is approximately 1/3. The middle column shows, however, that the cost of hauling the original advanced-treatment waste (at 1,000 gpd) by tank car is less at all distances than the cost of hauling an equal volume of solid mine waste by hopper car.

Table 2. COSTS OF HAULING 1,000 gpd OF WASTE BY ALTERNATIVE METHODS

Miles	$ 1,000 gal to pipeline	$ 1,000 gal to haul by tank car	$ 1,000 gal to haul equal volume of solid mine waste
1,000	392	73.0	117.5
800	315	—	102.0
400	163	39.2	68.7
300	126	—	56.5
200	87.2	26.9	47.0
100	46.7	22.0	34.8
50	25.4	17.0	26.1
10	6.66	12.7	17.4

The computation illustrates a type that must be ultimately made in comparing alternative disposal methods. Here, however, it is made simply to shortcut the analysis of the substitute disposal problem arising out of underground disposal in mined salt cavities. Incidentally, the analysis shows that hauling by tank car would be preferable for these small volumes. The intersection between tank car hauling and pipelining comes at approximately 30 miles, so that pipelining 1,000 gpd is cheaper below 30 miles and tank car hauling above. Correspondingly, the previously predicted breakpoint between pipelining and freighting in hopper cars is at approximately 60 miles.

CONCLUSION ON CREATING SALT CAVITIES

It may be concluded that, whatever the merits of mined underground storage as an ultimate disposal method for advanced-treatment waste, the disposal in salt cavities whether solution mined or conventionally mined may be summarily ruled out because the difficulties of disposing of the salt waste from mining would under all circumstances be more difficult, more expensive, and contribute more to environmental pollution than even the more expensive of the potential methods for ultimate disposal of the advanced-treatment waste itself.

Characteristics Of Underground Storage

Underground cavity storage was worked out for storage of petroleum hydrocarbons, the first installation being in a cavity dissolved in salt in Texas in 1949. Excavated caverns were first installed also in Texas in 1950. [6]

Table 3 shows the underground storage installations in the United States as of 1956.

Table 3. UNDERGROUND STORAGE, 1956[7]

Construction method	Matrix	Number of cavities	% of total capacity
Dissolving	Salt domes	69	35.8
	Salt beds	152	39.3
		Total	75.1
Mining	Limestone	1	0.1
	Shale	8	2.6
	Chalk	1	0.5
	Salt	0	0.0
		Total	3.2
Existing porous reservoirs	Oil or gas formation	8	16.3[a]
	Other formation	4	1.9
		Total	18.2[a]
Existing cavities	Rock quarry	1	3.5
	Mines	0	
	Tunnels	0	
	Salt	0	
		Total	3.5
TOTAL		244	100%

[a] Figure probably too large by severalfold.

Cavities in salt formations have been dismissed by the reasoning presented above, while ultimate disposal to existing reservoirs is treated in Part 1. The remainder of the present study is, therefore, concerned with underground storage in mined cavities exclusive of salt, and in existing cavities. The great bulk of storage in 1956 was in solution cavities in salt, only about 3 percent of the then existing capacity being in mined cavities. Most general discussions about underground storage perforce concern underground storage of liquefied petroleum gases in salt cavities. From 10 mined cavities of the type of interest in the present study in 1956, the number rose to 29 in 1960.[8]

In 1955 the largest mined cavern had a capacity of 260,000 barrels,[9] but larger ones were constructed subsequently. For example, Reference 9 describes the construction of a 675,000-barrel cavern in shale. In this installation there are five separate units connected by tunnels, each unit measuring approximately 400 x 240 x 20 feet high. The cavern is in a honeycomb structure with support pillars 35 to 50 feet square. The pillars actually occupy more space than the excavation; the over-all void space is computed at 39.2 percent.

COST OF MINED CAVITIES

The cost of mined caverns as well as of dissolved caverns and aboveground storage is reported as a function of capacity in Reference 7 for 1956 conditions. In 1960[8] typical costs of mined caverns were given as follows:

Fixed costs:	
Geological studies, tests	$ 25,000
Mine shaft incl sealing	100,000
Auxiliary drilled holes, piping	100,000
Pumps, valves, and gauges	75,000
Mine development	50,000
Total fixed	$350,000

Variable costs:
Excavation depends on labor cost,
typical value is $3/bbl

Computed as above at $350,000 fixed cost plus $3-per-barrel excavation cost, 1960 costs of caverns are taken as follows:

Capacity, thousand barrels	100	200	300	400	600	1,000	2,000	∞
Cost, $/1,000 gal	154	113	99	92	85.4	79.5	75.6	71.5

These figures lie satisfactorily within the ranges given in Reference 7.

The data of Reference 7 incidentally show the reason for the emphasis in using underground storage facilities for LPG storage. Aboveground storage (tanks) for nonvolatile materials such as diesel fuel, and kerosene, and water, costs only about \$1.20 to \$1.40 per barrel in capacities of 20,000 barrels and about \$1.00 per barrel at 100,000 barrels, not decreasing much beyond this. A typical cost for mined caverns at 100,000 barrels is \$8, and for dissolved caverns, \$2 per barrel. Obviously on a cost basis there is no incentive to use caverns for storage of nonvolatile materials except possibly where surface land is not available, or for damage protection, etc. The cost of aboveground storage increases, however, as the pressure requirements increase, so that for storage of propane at 250 psi the costs of aboveground storage have risen to \$15 to \$16 per barrel. For storing propane then, dissolved caverns or even mined caverns are preferable above 100,000-barrel capacity.

It may be concluded, therefore, that, for storage of a nonvolatile liquor such as the aqueous waste from advanced waste treatment, mined caverns could not compete with aboveground storage on a first-cost basis. Presumably, however, mined caverns have no upkeep cost whereas aboveground storage, in tanks, for example, would entail replacement after the safe life had been exceeded. This would involve a continual replacement cost. These relationships are only mentioned here and not computed because the present study is concerned only with underground storage.

TIME FOR MINING CAVERNS

A considerable period of time must be allowed for the construction of underground cavities. Some of this time varies with the size of the cavity and the remainder is a fixed time, according to Reference 8, as follows (in months):

Preliminary investigation	1
Site selection, land option	2
Coring, basic design, cost estimation	3
Detailed design	1
Total engineering months	7
Shaft construction	4
Testing and startup after mining	1
Total independent of volume	12

The time spent in actually mining a 200,000-barrel cavern is stated to be 7 months or 3.5 months per 100,000 barrels.

On this basis the number of months required for placing a cavern in operation from the time of beginning work is as follows:

Volume, thousand bbl	Months to complete
0	12
100	15½
200	19
400	26
800	40
1,000	47
2,000	82

AREA UNDERLAIN BY CAVERN

The large 675,000-barrel cavern described in Reference 10 has a 20-foot height. In 1956 mined caverns had a minimum height of 20 feet and a maximum height of 38 feet. For computation purposes of the present study two heights will be taken, 20 feet, the minimum, and 80 feet, which is about double the highest present practice. The voids in the cavern will be taken as 40 percent of the total volume.

On this basis 1 acre foot of cavern would contain 3.10 million barrels of voids and 1 square mile foot would contain 1.98 million barrels.

Rock Caverns By Conventional Mining

ECONOMIC CAVITY SIZE

As shown above, the unit cost of cavities decreases with cavity volume. If, however, an oversize cavern is constructed to achieve low unit costs, then added costs are incurred because of the fixed cost on the investment over the longer time period of cavern life. This means that there is an optimum cavern size for each capability; larger sizes will have higher costs because of increased amortization costs; while smaller sizes will have increased costs because of higher unit investment costs.

In computing fixed charges on the investment in the present study, a straight-line depreciation to zero value at the end of the life will be used, as well as a 4 percent per annum interest on the depreciated value computed at the midpoint of each successive year (which is the same as applying the interest to the midperiod depreciated value). For this method the yearly depreciation and interest as a fraction of the initial investment are given by:

$$\left(\frac{1}{n} + \frac{r}{2} \right)$$

where:

n = investment life, years
r = interest rate per year, fraction,

This results in yearly rates as follows:

Life, years	Annual depreciation plus interest, fraction of initial investment
2	0.52
3	0.353
4	0.27
5	0.22
7	0.163
10	0.12
15	0.0867
20	0.070[a]

[a] This figure for 20 years' life (taken from Reference 11), differs from the figure 0.074 used in AWTR-3.

To these fractions were added, in the present computation, 1 percent per year for taxes and 2 percent per year for insurance. The insurance figure has been increased because of the uncertainties and possible hazards of the construction and operation. Actually, for hydrocarbon storage, underground insurance rates are lower than aboveground rates because the hazard is less.[12]

This economic optimum computation falls down for the 10 million gpd case because an 87,000-barrel cavern would be required each year, and since the unit cost is approaching its infinity value, the economic optimum cavern life would be a matter of days rather than years. Since under the formula given it would require 250 years to construct a single cavern of 87,000-barrel capacity, this means that already with a 1-year cavern .

life it would be necessary to be constructing 250 caverns simultaneously continuously into the future. Accordingly the pseudoeconomic life of 1 year has been taken for comparative purposes.

SUMMARY

Table 4 summarizes the physical magnitudes and costs involved in mined caverns for the three capabilities of interest.

Table 4. DATA FOR MINED CAVERNS

		Capacity, gpd	
	1,000	100,000	10 million
Economic cavern life, years	14	2	(1.0)
Void volume of economic cavern, thousand bbl	121.5	1,740	(87,000)
Scaleup factor from largest existing cavity	0.18	2.58	130
Construction time, each cavity, years	1.35	6.1	254
Number of caverns under construction at any one time	1 cavern 1 year out of 10	3	254
Area underlain by one cavern, acres			
20 ft high	1.96	28.1	1,410
80 ft high	0.49	7.0	352
Area underlain in 100 years, acres			
20 ft high	14	1,400	220 mi^2
80 ft high	3.5	350	55 mi^2
Spoil, tons per day during construction,	104	1,040	104,000
mi^2 ft per 100 years	0.294	29.4	2,940
Cavity construction cost, $/1,000 gal created	136	76.2	71.5
Cost (fixed only) $/1,000 gal disposed	243	83.9	71.5

The 1,000 gpd case requires a cavern of a size well within present practice. The 100,000 gpd case needs a scaleup about 2-1/2 times over largest current practice, which seems reasonable. But the 10 million gpd cavern, to contain 1 year's flow, would represent a 130-fold scaleup.

To construct so large a cavern according to the formula used would require over 250 years, and thus 250 caverns would have to be under construction at any one time. In the 1,000 gpd case a cavern would be under construction only 1 year out of 10.

The area eventually underlain by caverns after 100 years of operation would be only a few acres for 1,000 gpd, several hundred acres for 100,000 gpd, and 50 to 200 square miles for 10 million gpd.

DISPOSAL OF SPOIL

Another physical magnitude of interest is the amount of spoil mined and its disposition. At a density in place of 2.5 this would amount to about 100 tons per day during the 1-year-in-10 construction period of the 1,000 gpd cavern. In 100 years the spoil dump would cover a square mile to a depth of about 3 feet. For the other two cases spoil production would be continuous and in 100 years would amount to about 30 square mile feet for 100,000 gpd and about 3,000 square mile feet for the 10 million gpd. (The bulk density of piled crushed stone is about 1.5 grams per milliliter.)

Neglected in the preceding has been the actual cost of disposing of the spoil. Unlike salt disposal, rock spoil could be dumped in some relatively nearby location. In the following section it is shown that credit taken for the spoil at $1 per ton would amount to 7 to 14 percent of the fixed cost computed in Table 4. If the cost of hauling spoil to a nearby dump were also $1 per ton the increase in total disposal cost would be these small percentages. Since the fixed cost alone is already so high this small additional cost is of no consequence. Because the actual cost would depend upon the hauling distance, consideration of it would add a new independent parameter. The rental cost of the dump land has also been neglected for similar reasons.

CREDIT FOR SPOIL

Interesting possibilities open up for the creation of real estate or other values in the handling of this spoil locally. Conceivably, for purposes of discussion, the spoil from mined caverns might replace some of the stone and the construction sand and gravel now produced in the nation. Table 5 has been constructed to facilitate this discussion. It shows the volume created by the production of construction sand and gravel and of stone, both surface and underground, in the United States in 1960. The two minerals accounted for the creation of almost 400 million gpd of cavity space of which 98 percent was created by surface mining. We will consider the proposition that spoil from underground cavities might substitute for some of this.

The total magnitude in the nation is sufficient to carry about 40 of the 10 million gpd cases considered in this study and about 4,000 of the 100,000 gpd cases. Furthermore, the distribution of production of stone and construction sand and gravel probably parallels closely the use of municipal and industrial water for which cavity space would be required. Like water, stone and sand and gravel are customarily consumed close to the point of production. Accordingly, so far as volume and distribution of production are concerned, mined-cavity spoil might find a commercial outlet replacing stone and construction sand and gravel.

The breakdown suggests, however, a need for some modification of this over-all conclusion. Contrary to what one might hope, the low-grade uses such as fill and railroad ballast take but a minor portion of the total production. The major portion of the sand and gravel goes into building and paving uses, that is, for making mortar and concrete. It is not clear that mine spoil could substitute in these uses. Certainly a considerable degree of crushing and preparation would be involved in reducing mine spoil to sand and gravel sizes. Major use of crushed stone is for concrete and for (concrete and asphalt) roads. Processed mine spoil could more easily meet the specifications for this material except when the spoil was shaly and friable.

At any rate the maximum credit that might be taken by the sale of mine spoil in place of construction sand and gravel and stone appears too small to affect appreciably the cost of creating cavities and thus the cost of disposal. The effect of credit for sale of spoil on disposal cost is shown in Table 6. For computation purposes it is assumed that the spoil would sell for a return of $10 per thousand gallons or approximately $1 per ton. This is a very optimistic figure since the cost of preparation would have to be deducted from it. Nevertheless, even at this optimistic figure, the disposal cost is reduced by only about 14 percent at 10 million gpd and about 7 percent at 1,000 gpd. It may be concluded that there is only a slim possibility that sale of spoil could significantly affect the cost of disposal to mined cavities. If, however, disposal to mined cavities should be undertaken in any locality, the availability of the spoil would have major repercussions on the stone and sand and gravel industries in the area.

Table 5. CAVITY VOLUME CREATED BY SAND AND GRAVEL AND STONE PRODUCTION, UNITED STATES, 1960

Mineral	Underground		Surface			Both		
	Produced, thousand tons/yr	Thousand gpd	Produced, thousand tons/yr	Thousand gpd	Density in place, lb/ft^3	Thousand gpd	Average value at point of production, $/ton	Valve of mineral per 1,000 gal created cavity volume
Construction sand and gravel, total		0	687,800	225,470		226,000	0.61	5.10
Building			232,000	76,000	125		0.61	5.10
Paving			408,000	133,800	″		0.61	5.10
Fill			30,200	9,900	″		0.20	1.67
Railroad ballast			5,900	1,930	″		0.20	1.67
Other			11,700	3,840	″		0.61	5.10
Stone, total	29,200	7,727	575,200	161,917		169,600	1.41	14.60
Dimension	1,200	317	1,200	317	155			
Crushed								
for concrete and roads	19,000	5,030	405,000	117,000	155		1.66	17.20
for other uses	9,000	2,380	169,000	44,600	″		0.81	8.40
Total sand and gravel plus stone	29,200	7,727	1,263,000	387,387		395,600		

Table 6. EFFECT OF SPOIL SALE ON DISPOSAL COST

	1,000 gpd	100,000 gpd	10 million gpd
Cavity construction cost, $/1,000 gal	136	76.2	71.5
Disposal cost (fixed only, $/1,000 gal	243	83.9	71.5
Assumed credit for sale of spoil, $/1,000 gal	10	10	10
Disposal cost with credit, $/1,000 gal	225	72.7	61.5

Rock Caverns By Nuclear Blasting

CHARACTERISTICS OF NUCLEAR CAVERNS

The possibility of constructing underground storage facilities with nuclear explosions has been suggested, and Carlson[13] provides some data on which computations may be based. Practically all the information concerning underground nuclear bursts is derived from the 1957 Rainier shot in which a 1. 7 kiloton device was detonated in loosely cemented tuff, with a typical porosity of 27 percent. It is assumed that extrapolations from the Rainier data would give a fair estimate of cavity size for sandstone with porosities in this general range, but that cavities formed in less porous rocks such as granite would be much smaller. The radius of the cavity produced by Rainier-like explosions is directly proportional to the cube root of the yield in kilotons. Thus the volume of the created cavity assumed as a sphere is directly proportional to the kiloton yield. The depth of burial necessary to contain the explosion completely is given by

$$D = 450 \times W^{1/3} \qquad (2)$$

where:

D = depth of burial, ft
W = explosive yield, kilotons.

The rock forming the ceiling of the cavity will collapse until the span formed can carry the overburden weight. For the extrapolated high-yield explosions, it is likely that extensive collapse would occur possibly to the ground surface. It is possible that as in the Rainier cavity a crushed and fused zone impermeable to water might be formed around the cavity. For the storage of oil the radioactivity surrounding the cavern is of major importance but for the storage of waste waters this seems of little importance.

The Rainier shots were placed by means of shafts and tunnels. A nuclear explosive of a few tens of kilotons' yield would have a diameter of about 30 inches, and one of a few thousand kilotons about 60 inches.

Carlson gives the charges for nuclear devices based on costs released by AEC and estimates on placement costs as indicated in Table 7.

Table 7. BASIC DATA ON NUCLEAR CAVITIES

Nuclear explosive yield, kilotons	Cost of nuclear device delivered, $	Cost of placement, $	Volume Created, thousand gal	Cavity cost, $/1,000 gal
1	320,000	120,000 extrap	2,940	150
10	600,000	225,000	29,400	28.0
100	850,000	400,000	294,000	4.25
1,000	1,000,000	750,000	2,940,000	0.595
10,000	1,000,000	1,000,000	29,400,000	0.0680

OPTIMUM SIZE OF CAVITY

As with conventional mined cavities an optimum must be struck between the decreasing unit cost of cavities with increasing size, and the fixed charges on the additional volume that is not immediately needed. The unit cost of nuclear cavities continues to decrease with size, unlike conventional mined cavities, which asymptotically approach constant-unit cost. Accordingly some different relationships in optimum life can be anticipated. The cost of disposal will be computed here in the same manner as for conventional mined cavities, and only these fixed costs will be considered. There is possibly a greater likelihood of continuing surveillance and maintenance costs for nuclear cavities, which would be greater than for conventional mined cavities. For our purposes, however, it is assumed that these costs will be negligible compared with the fixed costs.

SUMMARY FOR THE THREE CASES

Pertinent data for several cases are shown in Table 8. In considering first the 1, 000 gpd and 100, 000 gpd cases, the three figures given for optimum fill times are the ranges of a quite flat cost minimum, and the costs corresponding to the three figures are given in the last row of the Table. The data in the remainder of the Table correspond to the absolute minimum of 75 and 200 years respectively. It is seen that substantial variations from this optimum size introduce only slight percentage increases in the unit costs.

The required yield for the 100, 000 gpd case is 2, 480 kilotons, which would correspond to a device about 60 inches in diameter. Drilling a hole 60 inches in diameter to 6, 100 feet, the burial depth necessary to contain the explosion below ground, would stretch the limits of present drilling technology, but has reasonable expectation of accomplishment if necessary. Devices of these yields are relatively small compared with the largest known explosion reported to be in the 30- to 50-megaton range. The scaleup of 1400-fold from the 1. 7-kiloton Rainier test is probably excessive, even for nuclear scientists, but the theoretical basis for the extrapolation is sound.

Turning attention now to the third case of 10 million gpd, one reaches regions of high speculation. The scaleup factors themselves are in the quite unbelievable range, but the determinant here is taken as the burial depth necessary to contain the explosion. It seems most unlikely that burial depths beyond 6, 000 feet in the diameters necessary could be allowed on the basis of foreseeable technology, and the computations have, therefore, been restricted to that figure. Thus, although the true optimum life for 10 million gpd is something over 1, 000 years, and reduction of this figure to 100 years does not appreciably change the unit cost, the construction is computed for a 2-year life corresponding to the maximum burial depth of 6, 100 feet. Since this introduces a discontinuity in the data a computation on the same basis has been made for 1 million gpd.

Use Of Existing Cavities

It has been shown above that the cost of storage in underground conventionally mined cavities is very high because of the cost of creating the cavity, while the cost of very large nuclear cavities is comparatively low, but the construction of large nuclear cavities, particularly in populated areas, is a highly speculative undertaking.

Table 8. DATA FOR STORAGE IN NUCLEAR CAVITIES

	Thousand gpd						
	1	100	10,000			10	1,000
Optimum fill time, years	50-75-100	190-200-225	1,000	100	–	100	–
Actual fill time, years	–	–	–	–	2.0	–	20
Volume, thousand gal	27,375	7,300,000	$3,650 \times 10^6$	365×10^6	7,300,000	365,000	7,300,000
Diam of equal-volume sphere, ft	194	1,240		4,550	1,240	–	
Burial depth to contain, ft	950	6,100	48,000	22,500	6,100	–	6,100
Yield to create, kilotons	9.3	2,480	1.24×10^6	124,000	2,480	–	–
Scaleup from Rainier, -fold	5.4	1,430	720,000	72,000	1,430	–	–
Scaleup from largest known explosion (50 megatons), -fold	0.00018	0.05	24.9	2.49	0.05	–	–
Cavity cost,$/1,000 gal	30	0.245	0.00072	0.0064	0.245	3.50	0.245
Disposal cost (fixed only), $/1,000 gal	141-139-140	2.70-2.69-2.70	0.037	0.038	0.269	21.00	0.49

The mining operations of the country are, however, constantly creating cavity space in the earth and underground by the production of minerals. Here the possibility will be investigated that the cavity space being created by mining operations might be utilized for underground disposal. If this could be done the cost would become only that of preparing the cavity for storage of the wastes since the actual creation of the cavity would have been accomplished in the course of other operations at no cost against waste disposal.

LIMITATIONS OF EXISTING CAVITIES

While not subject to quantitative evaluation in the present study the use of existing cavities has a number of severe limitations that taken together make the procedure very questionable as a general solution for advanced-treatment waste disposal. Some of these are discussed here.

The ideal cavity for waste disposal would be constructed at such a depth in any location that it would be below the level from which ground water would ever be drawn. If this would not be done then it would be necessary to seal the underground cavern absolutely and completely against any seepage into the ground water. This would be a quite difficult feat, especially since it would be expected to last for the duration of mankind's habitation of this planet. Unfortunately the existing cavities and those being created by mining operations are not placed with such a thought in mind but follow the natural occurrence of the ores sought. For example, bituminous coal mines are notorious polluters of water supplies through acid mine drainage, which term in itself signifies that not only do the waters (e. g. , from abandoned mines) get into ground water, but they even get into the surface water by being at higher elevation.

If a mined-out space is used for advanced-treatment-waste disposal, it is intended that the space shall be given over to that use indefinitely. As technology advances, however, and the demand upon our mineral resources increases, it is likely, in the future as it has been in the past, that mine properties formerly regarded as worthless will become producing properties again. This point was strongly brought out in the preliminary studies on disposal of radioactive wastes by injecting them into depleted oil and gas fields. The recommendation of the petroleum industry was that one could not tell when an oil or gas field was "depleted" since not only the confident expectations of advancing technology but also numerous instances of actual occurrence in the past had shown that abandoned and exhausted fields have a way of once again becoming producing properties.

Although it is customary to think of mining as an underground operation, which creates underground cavities, the facts are, as will be shown later, that over 80 percent of the cavity volume created by current mining operations is created in the surface with less than 20 percent creating underground cavities. Except where these may occur in remote and isolated areas, disposal in surface cavities would almost automatically involve contamination of the ground water if not the surface water and would create hazards and nuisances.

Because mining follows the ore it is in general only by accident that the distribution of cavity creation would follow the distribution of waste treatment, particularly for underground cavities. As mentioned previously, cavity creation by the mining of crushed stone and construction sand and gravel is likely to follow population and thus follow waste treatment distribution. As will be shown later, however, underground cavity creation in the production of these commodities constitutes less than 1 percent of surface cavity creation from production of these commodities. The greatest extent of cavity creation underground is from bituminous coal mining, and it is true to some extent that bituminous coal mining has drawn population to it in a way that other mineral commodities have not been able to do. Thus most of the bituminous coal mining is done in the Northeast where most of the advanced-treatment waste will also be ultimately produced. The possibility of using bituminous coal mine cavities, though still subject to a number of deficiencies previously enumerated, is probably worth some further study.

RATE OF CAVITY CREATION

While it would take a lengthy specialized study to determine the volume of existing cavities, it is relatively easy to compute the volume of cavities being created each year by mineral production. Table 9 shows the results of such a computation.

Inspection of the Table shows that over 800 million gpd of cavity are created by actual mineral production in the United States each year, measured by 1960 production. About 81 percent of this cavity creation is in surface cavities, and major commodities are construction sand and gravel, crushed stone, and bituminous coal. In total, enough cavity, surface and underground, is created each year to handle the discharge from eighty 10 million gpd plants or from eight thousand 100,000 gpd plants. In brief, in total there is enough cavity creation that the subject cannot be dismissed by the simple arithmetic of the situation.

Table 9. CAVITY VOLUME CREATED BY ACTUAL MINERAL PRODUCTION (ORE AND WASTE) IN UNITED STATES, 1960 (ADAPTED FROM MINERALS YEARBOOK 1960)[14]

Mineral (major production itemized)	Underground		Surface		Both	
	Produced, 1,000 tons/year	Thousand gpd	Produced, 1,000 tons/year	Thousand gpd	Density in place, lb/ft^3[f]	Thousand gpd
Metal ores						
Copper	25,469	3,990			262	
Iron Ore	24,167	3,140			315	
Molybdenum	11,741	1,605			300	
Placer gold (dredged)[a]			52,542	17,900	120	
Titanium (dredged)[a]			24,000	3,280	300	
Other metals by diff	29,244	4,000	766,869	104,600	300 est	
Total metals	90,621	12,735	843,411	125,780		138,515
Nonmetals						
K salts	15,121	4,280	15,210	4,300	145	
Rock salt	6,770	1,910			145	
Salt in brine	15,023	4,250			145	
Industrial sand and gravel[b]	0		19,000	6,240	125	
Construction sand and gravel[b]	0		690,000	226,000	125	
Dimension stone[c]	0		2,500	660	155	
Crushed stone	29,365	7,750	585,289	155,000	155	
Mg compounds			42,700	12,100	145	
Other nonmetals by diff	7,948	2,170	315,775	86,200	150 est	
Total nonmetals	74,227	20,360	1,670,474	486,200		506,560
Solid fuels						
Bituminous limestone and sandstone[c]			1,243	365	140	
Gilsonite[c]			383	242	65	
Bituminous coal and lignite[d]	282,000	115,700	133,500	54,700	100	
Pa Anthracite[e]	7,600	2,840	11,300	4,220	110	
Peat			471	385	50	
Total fuels	289,600	118,540	146,897	59,912		178,452
Grand total volume created		151,335		671,892		823,527

[a] Not included in thousand gpd because does not create usable volume.
[b] Slightly adjusted pro rata to make breakdown sum conform to reported total.
[c] Not reported as to source; assigned to surface.
[d] From underground, 68% in 1959; assigned thereby.
[e] By stripping, 60% in 1959; assigned thereby.
[f] Perry's Chemical Engineers Handbook and other Handbooks. Some values assigned on basis of similarity to reported substances.

Since surface cavities seem to be contraindicated for reasons enumerated above, attention must be concentrated on underground cavities. The volume of these is enough to handle fifteen 10 million gpd plants or fifteen hundred 100,000 gpd plants. Of the 152 million gpd created, however, about 116,000 is from underground mining of bituminous coal and lignite. Bituminous coal and lignite mines occur in a long strip through the Appalachian province and in the northern Midwest with isolated occurrences elsewhere. This is not remote from the centers of industry and population, and thus is conceivably within striking distance of the waste-producing points, but the percentage of abandoned bituminous coal and lignite mines that would be suitable for waste disposal cannot be determined in this preliminary study. The fact has, however, been demonstrated that the total volume created each year is ample to take care of many disposal units.

The uncertainty with regard to the percentage of created volume that is suitable for disposal exists with respect to all of the other commodities listed in the Table. A word about rock salt and salt in brine is in order, since so much present-day storage is in salt deposits. Indeed the use of salt deposits for storage is being taken into consideration in the development of new salt facilities. For example, in 1960 new salt production came in near Williston, South Dakota. The deposit is 8,000 feet below the surface in a bed 230 feet thick and the operating company plans to lease the created cavities for LPG storage.[14] These possibilities are bound to have some impact on salt production, economics, and distribution. Numerous studies, not referenced here, have been made concerning the distribution of salt mines and salt deposits in the nation. Utilization of the creation of existing cavities in salt by commercial production of salt (and this is the only method that can be considered here, as shown above) has been suggested and considered not only for waste disposal, particularly radioactive waste, but also for the storage and safekeeping of documents and other valuables. The total volume created each year is, however, only about 6 million gpd, which would take care of only sixty 100,000 gpd waste plants. This is not a large number considering the ultimate total needs of the nation and the probable sizes of the advanced-treatment plants themselves. If, however, advanced-treatment plants typically produced 1,000 gpd of waste for disposal, then the created salt volume would take care of 6,000 of these. In addition, there are the potassium salt mines, mostly in New Mexico, which would contribute another 4 million gpd of created volume, but at a point rather remote from probable waste production points.

Ultimately the use of commercial salt cavities for waste disposal might influence the distribution of salt production, but in the beginning at least the disposal pattern would have to conform to existing distribution. This necessity involves the logistics of moving the waste to the existing salt mines when they are abandoned and, of course, a comparison of the economics of this method with the corresponding method of moving the waste directly to the ocean.

DIFFERENCE FROM RADIOACTIVE WASTE DISPOSAL

Since a great deal has been said in the literature about storage of high-level radioactive waste in salt cavities, a word is in order about the differences between that program and the present problem. In the first place the disposal of radioactive waste involves not only the disposal of liquid waste but also of solid waste, waste packaged in drums, and the like. Storage of drums of waste in abandoned salt mines is, of course, a quite different situation from disposal of liquid waste in bulk.

Second, the costs involved in disposal of high-level radioactive waste are extremely high compared with any costs that could be taken in disposal of advanced-treatment waste. It is common in the atomic energy waste disposal program to discuss high-level waste disposal costs of the order of dollars per gallon, whereas for the advanced-treatment waste we seek disposal methods with costs of cents per thousand gallons. See for example Reference 15. Low-level waste is discharged to the environment, that is, to streams and the ground at much lower treatment and disposal costs.

Third, although the research and engineering activity is great, and the health hazard is undoubtedly paramount, the total volume of radioactive wastes to be disposed of is, nevertheless, very small compared with advanced-treatment-waste volumes. For example, in 1957[16] it was estimated that the production of high-level radioactive waste in the entire nation in 1980 would be at the rate of 137,000 gpd and in the year 2000 at about 550,000 gpd. In contrast, by 1980 the municipal and industrial water use of the nation will probably be about 300 billion gallons per day. If advanced waste treatment were applied to all of this water and achieved a 99 percent recovery the waste would amount to 3 billion gpd. Even if 99.9 percent recovery of all municipal and industrial water were achieved, the waste would amount to 300 million gpd, or more than 2,000 times as much as the anticipated high-level radioactive waste.

For the above reasons the disposal of high-level-radioactive, liquid waste is a problem of a very different order of magnitude from the disposal of advanced-treatment waste, and, while there are similarities and areas of cooperation between the programs, the achievements of the one cannot be directly translated into achievements for the other.

CONCLUSIONS

Determination of the extent of cavities already created is beyond the resources of this study, but the cavity volume being created annually by underground mining operations would provide volume for a significant amount of advanced-treatment waste if all such cavity volume were suitable as disposal cavities. The determination of the extent to which they are suitable would, however, require a field study. The greatest underground cavity volume is created through bituminous coal and lignite mining followed at a much lower magnitude by crushed stone, sodium and potassium salts, copper, and iron mining. The problems of distribution of the cavity volume being created and the transportation necessary to balance this against the distribution of advanced-treatment waste production are beyond the scope of this study.

Surface cavity volume is created at a rate about four times that of underground volume, but surface storage is considered beforehand as unsuitable for advanced-treatment waste.

The emphasis upon salt cavity storage for radioactive waste cannot be translated into optimism for that type of disposal of advanced-treatment waste, for the problems differ in a number of parameters by several orders of magnitude.

Correlation Of Costs

UNIT COSTS

Figure 1 shows the unit costs of disposing to underground cavities. For very small daily rates disposal to conventional mined cavities approaches the cost of disposal to nuclear cavities. At increasing rates, however, the unit cost for nuclear cavities falls off very rapidly, whereas that for conventional mined cavities remains constant. Thus, with the reservation that the large nuclear cavities involve a high degree of speculation and high scaleup from present knowledge, it may be concluded that large conventional mined cavities are well out of the running compared with nuclear cavities.

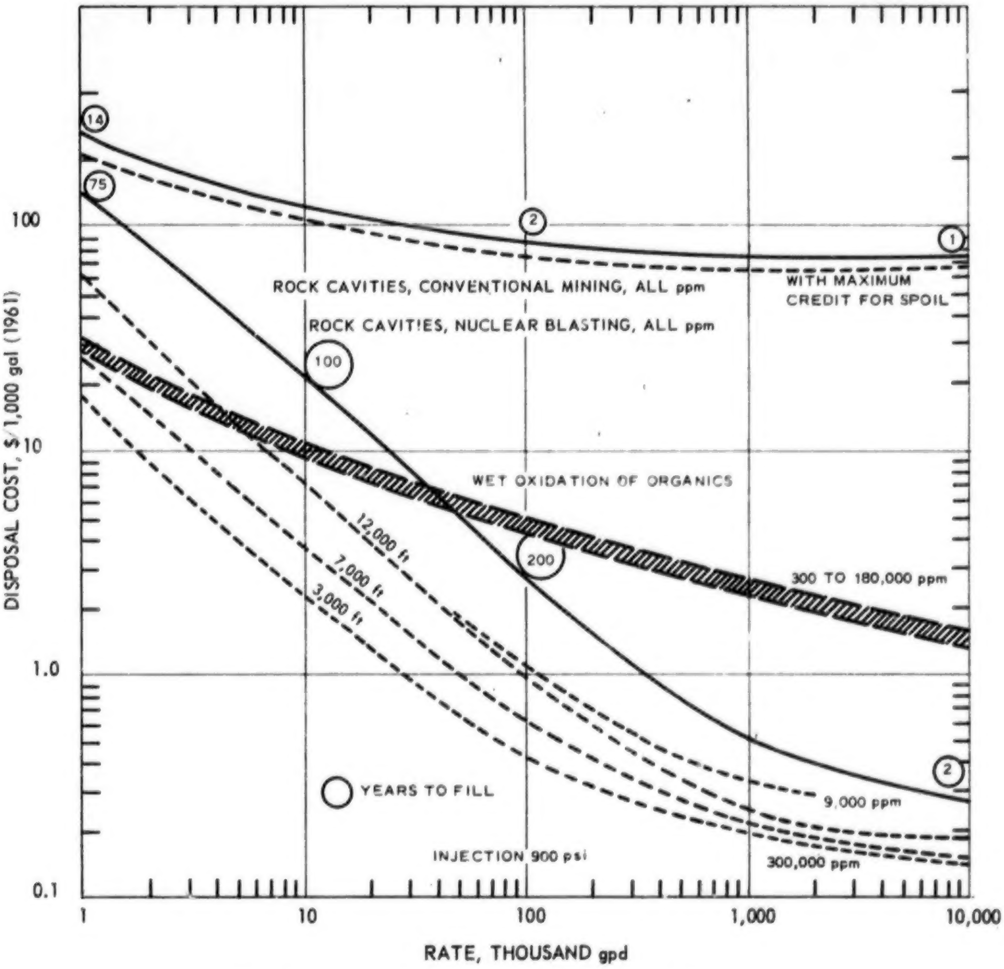

Figure 1. Unit cost of disposing to underground cavities (and comparison with other methods).

COMPARISON WITH OTHER METHODS

In the same Figure are shown the data from the author's previous report in this series (AWTR-3) and from Part 1 of this report. It is seen that injection is less expensive even than nuclear cavities at all rates, even when the disposal formation is as deep as 12,000 feet. It should also be pointed out that the curves shown for injection apply to the most expensive case of 900 psi standard wellhead pressure. For comparison: where the 12,000 foot curve shows $0.21 per thousand gallons at 2 million gpd, the corresponding zero psi curve would show $0.13. It should also be noted that the costs of disposing to underground cavities shown in the Figure are only the fixed costs on the installation. Data are not available on the other operating costs of disposal to underground cavities such as maintenance, surveillance, etc., and these when determined will increase the costs of underground cavity disposal, but probably by only a small amount.

ECONOMIC CHOICE

The correlation on the basis of tons per day of contaminants fed and daily disposal cost is shown in Figure 2. As in the previous reports in this series the correlation is shown as a gridwork consisting of horizontal lines of constant daily rate and curving lines of constant concentration. On the same Figure are plotted as dotted lines the skeleton of the grid for injection. It is seen that nuclear cavity disposal is about five times as expensive as injection at 7,000 feet when the daily rate is 1,000 gpd, but 100,000 gpd could be disposed by injection for the cost of disposing of 1,000 gpd by nuclear cavity storage, and 1 million gpd could be disposed by injection for less than the cost of storing 100,000 gpd in nuclear cavities. For very high rates of 10 million gpd the difference is, however, not so great. On the Figure the position of conventional mined cavities may be visualized. The daily cost at 1,000 gpd would be about twice as great as that for nuclear cavities and at 10 million gpd would be 250 times as great.

INTERRELATION WITH ADVANCED TREATMENT

In Table 10 and Figure 3 are shown the disposal costs in dollars per million gallons of water produced in the advanced treatment as a function of the percent recovery. As with the previous examples in this report the advanced-treatment feed consists of 10 million gpd of secondary effluent containing 300 ppm of total contaminants (100 organic and 200 inorganic) from a community of approximately 60,000 population, and containing 12.5 tons per day of total contaminants. Also shown on the Figure are the corresponding curves for wet oxidation, for injection at 7,000 feet and 900 psi, and for incineration with a $10 per ton haul, including the pre-evaporation water.

Disposal to nuclear cavities shows generally lower costs than incineration or wet oxidation. Disposal to mined cavities would show much higher costs than any of these. Nuclear cavity disposal for these conditions does not, however, approach injection disposal, which averages about one-fifth the cost of nuclear cavity disposal.

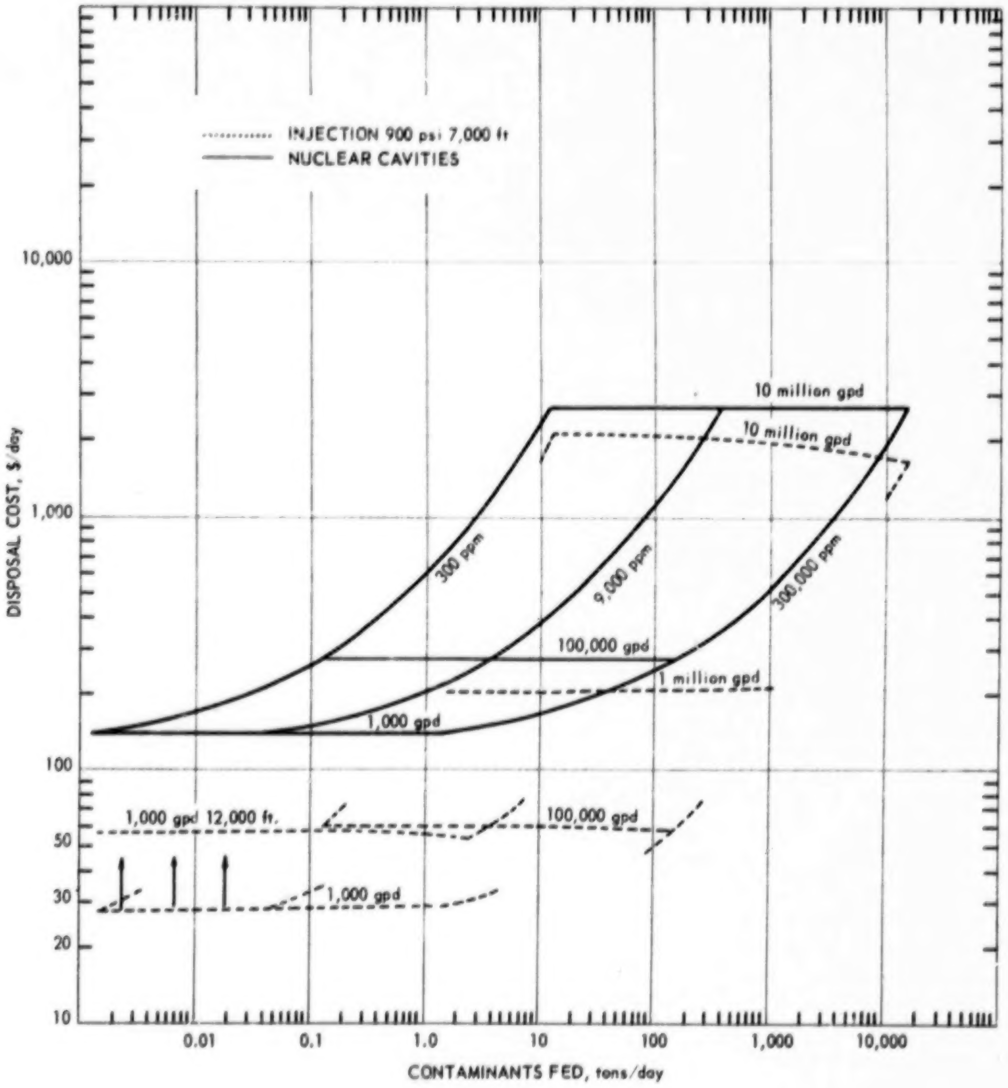

Figure 2. Economic choice: nuclear cavities and injection.

Table 10. DISPOSAL COST AS A FUNCTION OF PERCENT RECOVERY

Recovery of product water in advanced treatment, %	Contaminants in advanced-treatment waste, ppm	Disposal cost, $/million gal product water			
		Wet oxidation	Injection	Incineration (includes pre-evap'n water)	Nuclear cavities
99.90	300,000	–	3.20	24.0	17.4
99.83	180,000	15.5	3.80	–	–
96.67	9,000	91.1	10.5	80.1	43.4
80.00	1,500	538	50	192	111
50.00	600	–	196	335	300

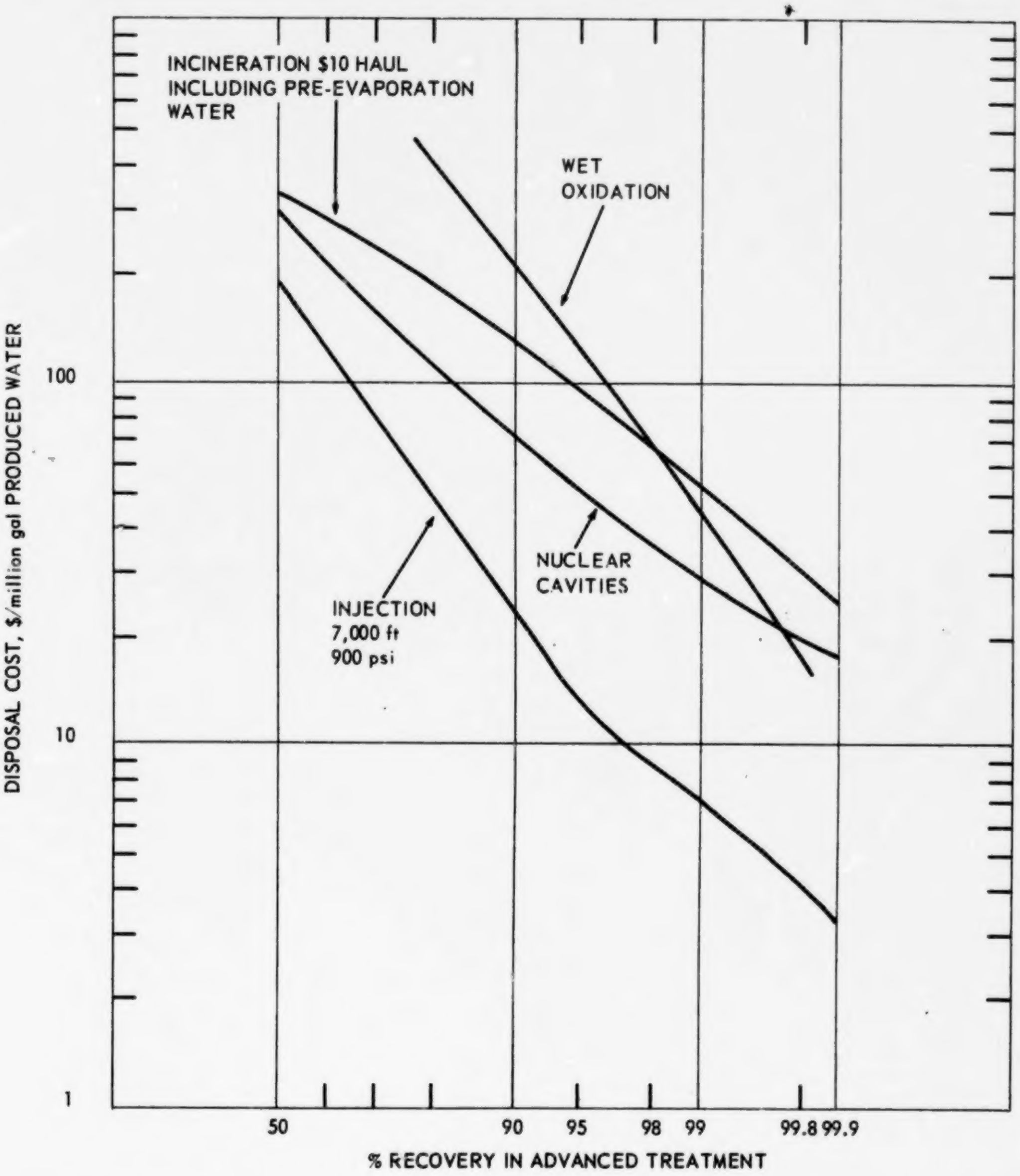

Figure 3. Cost of disposal per million gallons of produced water, 10 million gallons, secondary effluent 300 ppm.

There may be some questions concerning the examples used in this series of reports in that injection is uniformly much lower in cost than the other methods, despite the fact that at very low capabilities injection approaches the costs of the other methods, while at very high capabilities nuclear cavity disposal at least approaches the cost of injection disposal, as may be seen in Figure 1. One would, therefore, expect some areas in which nuclear cavity disposal in the terms of Figure 3 approaches the cost of injection disposal. There are such conditions, but they are not the conditions of the example, which deals with capabilities between 50 percent and 99. 9 percent recovery from 10 million gpd, with, in other words, disposal capabilities of 5 to 9. 99 million gpd. The relative positions of the various processes in this example depend on the daily volume chosen for the illustration. At volumes substantially higher than 10 million gpd, underground disposal (to nuclear cavities) would show lower costs, closer to incineration, but still not equal to injection. At substantially lower volumes than 10 million gpd, there would be considerable interchanging of relative positions, and injection would lose much if not all of its cost advantage over the other methods. In any case the costs per million gallons of produced water at any given percent recovery would decrease as the daily volumes increased.

Similar analyses can be made for other daily volume conditions and for other parameters by using the data presented in this report and others in the series.

Areas For Further Investigation

If serious consideration is to be given to disposal by placement in underground cavities, a number of areas must be investigated beyond this preliminary study.

The 1961-62 series of underground nuclear tests should provide a great deal more data to firm up the quite sketchy data used in this report on costs and particularly on the feasibility of large-scale nuclear cavities. Indeed it is probably not worthwhile to attempt to improve the present study until these data can be correlated and used in it.

The volume created annually by bituminous coal mining is shown to be substantial compared with the disposal volumes considered in this report. In addition there are the existing volumes in abandoned bituminous coal mines, but to determine their suitability for disposal it would be necessary to study them in the field with particular attention to their elevation with respect to the ground water supply, their tightness or ability to be sealed, and their distribution with respect to the expected production of advanced-treatment waste.

The volume of existing cavities, from mining of both bituminous coal and other minerals, has not been determined in this report. The underground volume created annually in other mineral mining is about one-fourth of the volume created in underground bituminous coal mining. The same sort of study is called for as recommended for bituminous coal mines.

It must be remembered that the present study is a general one. It is quite possible that existing cavities might be utilized for disposal in particular instances where they are suitable, available, and close to the waste-producing point. The possibility of finding such a special situation in connection with a particular advanced-treatment plant should never be overlooked, merely on the basis that in general the prospects for underground disposal are poor.

The present report has found no way to determine or estimate the cost of maintenance and surveillance of underground cavities over indefinitely long periods. Some effort should be made in any subsequent study to develop costs for these. This, of course, will increase the costs as developed in the present report, probably to a small extent.

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ULTIMATE DISPOSAL BY SPREADING

Part 3.

SPREADING

Summary

A preliminary process design and cost estimate was made for the ultimate disposal of liquid waste by spreading, which means distributing the waste on the ground surface and allowing it to seep into the ground. The daily volumes taken were 1, 000, 100, 000, and 10 million gpd. For purposes of this estimate, the concentration of contaminants was considered not to be a parameter in spreading. Other independent parameters were the infiltration rate and the cost of land.

An analysis was made of data from a number of operating spreading operations to develop design data and practice, including costs. The median infiltration rate for water spreading was 3. 5 fpd, while for treated sewage it was 1. 0. Equations were developed for the costs of earth dike ponds as a function of capability, infiltration rate, and land cost. Cost estimates and pond area determinations were made for infiltration rates of 0. 4, 1. 0, and 4. 0 (fpd) and land costs of $25, $150, and $1,000 per acre. The unit cost of spreading, dollars per thousand gallons, is roughly a negative exponential function of the infiltration rate and varies surprisingly little with land cost. This suggests that expensive land is not particularly a deterrent to disposal by spreading. Spreading costs varied from approximately $0. 30 per thousand gallons at 1, 000 gpd and 0. 4 fpd infiltration rate to about $0. 0005 per 1, 000 gallons at 10 million gpd and 4. 0 fpd. These costs are 1 percent or less of the costs of corresponding capabilities for any other disposal method investigated. The cost of conveyance even a short distance from the plant to the spreading grounds would seriously detract from the low-cost advantage for spreading.

The investment costs varied from $0. 22 per gpd to $0. 00064 per gpd between the highest and the lowest cases. The pond acreage involved ranged from 0. 001 to 115 acres.

Despite these very low costs, spreading is concluded to be not generally applicable because little purification of inorganics occurs in seepage through the ground and the underlying ground water would, therefore, be polluted with the wastes.

Consequently, spreading is applicable as an ultimate disposal method only in areas where there will be no future use for the ground water, or where the ground water is of such low quality that it can be considered as of no forseeable value. This limits the general applicability of spreading to basin areas hydrologically enclosed.

The need for studies on the fate of specific organic pollutants in spreading is indicated to determine if spreading might be used as an intermediate disposal step.

Spreading As A Recharge Method

"Spreading" may be defined as the dispersal of liquids on the land surface for the purpose of inducing their infiltration into the ground. Spreading has been applied both to natural waters and to waste waters. With natural waters the purpose has always been the recharge of ground water reservoirs for later use. This has been the purpose with waste waters also, but sometimes wastes have been spread simply as a disposal method without regard to future use of the recharged ground water. Spreading is ordinarily accomplished by ponding the waters, and this is the sense in which the term is used in this report. Spreading of waste waters, and also of natural waters, must be distinguished from direct use of these waters, as in irrigation, in which the primary purpose is irrigation, and recharge is accomplished only incidentally thereto.

Reclamation of waste waters by spreading has been extensively practiced and somewhat less extensively studied. For waste waters the most common operation is the spreading of primary sewage effluent or secondary sewage effluent. Studies have been made on the infiltration rates achievable with various types of soil, the effects of various treatments and modifications in improving the infiltration rate, the changes in water quality, both organic and inorganic, that occur subsequent to infiltration, and the correlation of lysimeter experiments with field data.

TYPICAL INFILTRATION RATES

A most important consideration in spreading is the infiltration rate, in fpd, achievable in various types of soil and with various types of waters. Parameters affecting infiltration rate are depth to the water table (a high water table lowers the infiltration rate), the standing head of water above the surface (approximately proportional to the surface head when soil resistance is high and little influenced by surface head when resistance is low), time in the spreading cycle, and type of surface treatment. It is characteristic that a high infiltration rate is achieved when water or sewage effluent is first applied. There may even be an increase with time, thought to result from the dissolving of air by the liquid, followed by a substantial decrease of infiltration rate. These changes occur during a period of several days. It has become customary to run a spreading bed for a certain period of time and then allow it to drain and dry, after which the surface is mechanically cultivated to put it in shape for the next cycle. A substantial portion of the cycle is composed of the low infiltration rate stage. The average infiltration rate is, therefore, not greatly influenced by the initial high-rate period, and it is this average rate per operating day that is considered in the following.

To form a concept of typical infiltration rates achieved in practice a statistical analysis was made of the infiltration rates mentioned in an annotated bibliography on recharge through 1954.[1] Three different situations were listed in the bibliography. One was spreading of water, one spreading of sewage effluent either primary or secondary, and the third was simple irrigation with sewage treatment plant effluent. The results of the statistical analysis are shown in Table 1.

Table 1. STATISTICAL SUMMARY OF REPORTED INFILTRATION RATES (PERCENT OF ENTRIES WITH RATES, fpd, LESS THAN INDICATED VALUES)

Condition	Percent of entries			Maximum Value of Infiltration rate, fpd	Number of spreading facilities
	10%	50%	90%		
Water spreading	3.0	3.5	18	113	123
Treated sewage spreading	0.4	1.0	1.1	1.2	10
Irrigation [a]	0.003	0.012	0.06	0.09	7

[a] The data on irrigation infiltration rates are presented simply to emphasize that these rates are at least an order of magnitude lower than spreading rates.

It is seen that for water spreading, though there is a reasonable percentage of high values (the 113 fpd extreme is for pea gravel pits at Peoria, Illinois) the median is but 3.5 fpd. With treated sewage the median is 1.0 fpd and the extreme is only 1.2. It is stated that if even as high as 0.5 fpd is to be maintained on a fine soil only a highly treated sewage effluent can be applied.

EXPERIENCED COSTS AND OTHER EXPERIENCED PARAMETERS

From the annotated references in Reference 1, all references dealing with costs, either spreading costs or capital costs, were taken. Some were actual experienced costs, while others were pre-construction cost estimates. Some adjustments were made in a few cases where the supporting data were available. In all cases the referenced data were adjusted to an Engineering News-Record Cost Index of 850, which corresponds approximately to 1961. The results are shown in Table 2. The thousand gallons per day (average) alludes to the seasonal operation of all of these spreading projects. They are operated only when the surplus water is available, which is ordinarily in the winter months. The thousand gallons per day is computed by taking the total water spread and dividing by the number of days in the season including those days when the beds were shut down for cultivation. The infiltration rate, however, is based on operating days not including the cultivation periods, and also refers to the wetted area (or more precisely to the area subject to wetting), which is less than the gross area because of the dikes and other construction works.

EXPERIENCED OPERATING FACTORS

Similarly selected from Reference 1 were data bearing on operating factors, here defined as the percentage of time per season in which spreading is underway in a given pond. The seasonal nature of the water-spreading operation, based on availability of water, cannot, of course, be carried over to disposal of advanced-treatment waste, which must continue the year round. Accordingly the seasonal operation is an artifact so far as advanced-treatment waste disposal is concerned, but the intermediate shutdown periods would still apply. The various projects may vary in the length of the cycle; some, for example, may operate 15 days and shut down for cultivation for 3 days, while others may operate for 6 months and shut down for 2 weeks.

Table 2. EXPERIENCED SPREADING COSTS AND ASSOCIATED DATA

Date	Project	County	Average, thousand gpd	Acres	Rate, fpd (operating day, wetted area)	Capital cost, $/acre	Acres per basin	Spreading cost, $/1,000 gal	Ref.
1934	Tujunga	Los Angeles	94,500	47, in 51 basins	6.2	5,430	0.92	0.0087	2
1934	–	Santa Clara	–	–	2.0	–	–	0.00202 labor and materials only	3
1936	Saticoy	Ventura	17,300	97	1.8	–	–	0.00232	4
1936	San Antonio	Los Angeles			0.97	–	–	0.00202	5
1937	Tujunga	Los Angeles	779,000 max capacity	397	6.0	1,265 construction	(0.92)	–	6
1939	Rio Hondo	Los Angeles	–	–	2.4	–	–	0.0127	7
1940	San Gabriel	Los Angeles	–	–	2.1	–	–	0.0203	8
1946	Rio Hondo	Los Angeles	26,000	40	–	–	–	0.0334	9
1946	Rio Hondo	Los Angeles	ca 260,000	ca 400	–	–	–	0.020	9
1949	(Sand Beds)	Los Angeles			high	–	–	0.00356	10
1954-6	Pit No. 1	Peoria	2,180	0.229 (wetted)	29.0	436,000		0.045	11
1951	–	(Southern Calif.)	–		–	1,240 to develop	(0.92)	0.0041 to 0.024 calc 0.00271	12
1952	–	–	–	–	–	–	–	0.0092 to .037 depending on land cost	13
1954	–	–	–	150 and up	–	–	–	0.0333 (about 1/2 is cost of land development)	14

The experienced operating factors as computed are shown in the following:

Project	Operating factor $\frac{\text{wetted time}}{\text{cycle time}}$, %
Rio Hondo	67
Rio Hondo	50
Azusa	80
Tujunga	91
Tujunga	84
Des Moines	97
"Los Angeles"	50
Madera	67
Lodi	92
"Calif."	50
Average	73%

LAND UTILIZATION

The basin method of spreading utilizes 75 to 80 percent of the gross area as wettable, while the furrow method utilizes only 12 to 20 percent. Furrows are cheaper to construct than basins, but require more land since the wetted area is lower. Where land values are very low, furrows may, therefore, have some economic advantage.[12] Nevertheless, the present practice is overwhelmingly in basins.

LAND COSTS

A map showing the average value of land and buildings per acre in 1954 is reproduced as Figure 7-1 of Reference 15. The United States average for land and buildings was $84.25 per acre in 1954. Only a small portion of the land was valued at more than $150 per acre, and this appeared, of course, around the large cities and in the Iowa-to-Ohio farm belt. About one-fourth of the country, in the West, was valued under $25 per acre.

BED MAINTENANCE

The spreading literature surveyed contained only one mention of the actual cost of maintenance.[12] Adjusted to 1961 this figure is $124 per acre annually, which is taken to include the cost of repairs and maintenance as ordinarily understood as well as of the cultivation and preparation of the beds between cycles.

A figure for comparison is found in Reference 15 in which it is computed that maintenance for lined irrigation canals is \$51.30 per acre year and, for unlined, \$89.50. Maintenance on unlined canals consists mostly of weed eradication. The latter reference is, however, concerned with ponds used as evaporation basins and so can be expected to be low compared with maintenance for spreading.

Spreading Costs

CHOICE OF PARAMETER VALUES AND OTHER CONDITIONS

In this section computations for spreading will be made, as predesign cost estimates, under various reasonable values of the parameters. No distinction will be made among the three concentrations used in this series of reports. It will be assumed that the characteristics for spreading will be the same regardless of the concentration. This is undoubtedly not strictly correct, but there is no way of determining the magnitude of any changes that may occur. The capabilities will be taken as with the other reports as 1,000, 100,000, and 10 million gpd. Three infiltration rates, namely 0.4, 1.0, and 4.0 fpd, will be used, which correspond to the 10 percentile, the median for sewage effluent, and a high value not actually achieved for sewage effluent but approximating the median for water. The values of land per acre will be taken as \$25, representing cheap land in the West; \$150, representing approximately the highest prices outside the metropolitan areas; and \$1,000.

Other conditions used in the computations are as follows:

Maintenance cost	\$125/acre year for pond areas greater than 0.1 acre
Dike cost	\$0.46/yd^3
Dike cross section	8 yd^2
Shape of individual ponds	square
Number of ponds	three per installation and not adjacent
Utilization of land	75%
Load factor	66.7% of 365 days or two out of three ponds operating at all times
Interest rate	4%
Depreciation of construction	40 years
Taxes	1% of investment annually
Insurance	1% of investment annually

THE COMPUTATION EQUATIONS

The above conditions lead to the following expressions for spreading cost, dollars per thousand gallons, for unit investment, dollars per gpd, and for area of ponds, acres, (= 75% of the gross area required) in terms of the three independent parameters:

Capability, Q, thousand gpd

Infiltration rate, i, fpd

Land value, L, \$/acre

Spreading cost, \$/1,000 gal

Fixed for land	$0.00000101 \frac{L}{i}$
Fixed for construction	$\frac{0.02140}{(iQ)^{\frac{1}{2}}}$
For maintenance	$\frac{0.00158}{i}$

Area of ponds, acres

$$Ap = 0.00461 \frac{Q}{i} \qquad (1)$$

Unit investment, \$/gpd

Land	$0.00000615 \frac{L}{i}$
For construction	$\frac{0.1205}{(iQ)^{\frac{1}{2}}}$

CONSTRUCTION COSTS COMPARED

The above conditions give the cost of construction of the dikes as:

$$\frac{1021}{Ap^{\frac{1}{2}}}, \text{ \$/acre (for square ponds)}$$

The only figures in the data for capital cost of construction are for the Tujunga project. When the project was actually constructed it contained 47 acres in 51 basins, 100 by 400 feet each, or 0.92 acre per pond. The 1961 equivalent cost was \$5,430 per acre, but when the project was estimated at the maximum capacity of 397 acres, the 1961 equivalent construction cost was estimated at $1,265. A separate 1951 figure for construction in southern California of unknown pond area was $1,240 per acre, which was close to the latter figure.

The formula developed in this work computes to $1,057 per acre for a 0.92-acre pond. The difference between the $1,000 to $1,200 figures and the $5,430 figure is unexplained, but possibly the $5,430 includes clearing of the land and very likely also includes the purchase price of the land itself. The difference between the $1,057 per acre here computed and the experienced figures of $1,240 and $1,265 is not significant. Consideration of the cost of control works, access roads, and other accessories would increase the estimate. Use of the assumed figure of $0.46 per cubic yard for dike construction and the assumption that the ponds are 400 by 100-foot rectangles rather than squares, give a cost per acre of $1,336, even without consideration of these auxiliary facilities.

PHYSICAL REALITY OF THE FORMULAS

The formulas used for shortcut estimating have been developed on the basis of large-scale water-spreading operations, which in general are larger even than the 10 million gpd case considered here. The physical reality of the structures and operations developed by the formulas begins to fall down as the pond size decreases. This factor has been investigated. The formulas are compatible with actual structural and operational visualizations of the processes down to 1 acre total pond area. Below this the physical reality breaks down for some components, but down to a pond area of 0.1 acre, these particular components happen to make up only a very small part of the total cost, so that even major increases in the unit costs, even their doubling or tripling, still do not make an appreciable increase in the total cost as computed. At 0.01 total pond acres and below, however, the formulas produce unreasonable component costs in important components and so cannot be applied.

The cost components were computed as follows for total pond areas below 0.1 acre, namely, for the 1,000 gpd cases. It was assumed that instead of dikes the ponds would consist of pits 5 feet deep excavated with a drag line or power shovel. Even the largest pond would involve only about 1 hour's work for a power shovel, so a flat rate of 1/2 day's charge was assessed. Reference 16 shows daily costs of $250 for power shovels or drag lines corrected to 1961. The excavation would include the indicated area for the pond bottom plus sides sloping to the ground surface over a horizontal distance of about 8 feet peripheral to the pond. Land utilization was assumed at 75 percent.

Maintenance for the small ponds was taken as 1/2 a day (4 hours) once a month. Labor cost was assumed to be $2 per hour. The pond bottoms for the three infiltration rates were 13, 8, and 4 feet square, respectively, for each of the three ponds. Gross land costs for the smallest pond was taken as the same as that for the 8 foot square ponds. Over 90 percent of the estimated spreading cost in these nine cases is the maintenance cost.

COMPUTED COSTS

Application of the above equations and other computations of the parameters results in the costs (and pond areas) shown in Table 3.

These data are plotted in Figure 1 as functions of the three parameters over the chosen ranges. Also plotted in the Figure are the experienced costs from Table 2. It is seen that the computed costs fall in the same general range as the experienced costs. Actually the 10 million gpd capability curves are the ones that should be compared with the experienced costs since the experienced costs apply to capabilities of over 10 million gpd. (Note that the trend of the curves is such that even capabilities much greater than 10 million gpd would show costs close to these curves -- that is, not much further decrease of unit costs is achieved at higher capabilities (see Figure 3). On this basis the computed costs are low compared with experienced costs. We will, however, use the computed costs because of the great uncertainty about the parameters used in arriving at the experienced costs.

Another interesting and surprising peculiarity is that the effect of land cost is not nearly so great as might be expected. For example, at 100,000 gpd, a cost rise from $25 to $1,000 per acre does not even double the unit cost of spreading. Since the unit costs are already extremely low, that is, considerably lower than any other disposal method investigated in this series, one might actually consider use of rather high-priced land, say $1,000 to $2,000 per acre and still maintain costs below those of any other disposal method. The difference between $25 land and $150 land is quite inconsequential. These relationships, for two infiltration rates, are shown in Figure 2.

COMPARISON WITH OTHER DISPOSAL METHODS

A correlation according to capability is shown in Figure 3, where a comparison is made with the unit costs of wet oxidation, of injection, of incineration, and of placement in underground

Table 3. COMPUTED SPREADING AND INVESTMENT COSTS[a]

Capability, gpd	land cost, $/acre	Infiltration rate, fpd								
		0.4			1.0			4.0		
		Spreading cost, $/1,000 gal	Investment cost, $/gpd	Pond bottom, acres	Spreading cost, $/1,000 gal	Investment cost, $/gpd	Pond bottom, acres	Spreading cost, $/1,000 gal	Investment cost, $/gpd	Pond bottom, acres
1,000	25	0.285	0.127	0.0115	0.285	0.126	0.0046	0.285	0.126	0.00115
	150	0.288	0.140	0.0115	0.286	0.132	0.0046	0.286	0.132	0.00115
	1,000	0.302	0.225	0.0115	0.294	0.175	0.0046	0.294	0.175	0.00115
100,000	25	0.0074	0.0194	1.155	0.00371	0.01220	0.461	0.00146	0.00605	0.1155
	150	0.0077	0.0213	1.155	0.00384	0.01297	0.461	0.00150	0.00624	0.1155
	1,000	0.0098	0.0344	1.155	0.00469	0.01820	0.461	0.00172	0.00755	0.1155
10,000,000	25	0.00435	0.00227	115.5	0.00181	0.00136	46.1	0.00051	0.00064	11.55
	150	0.00467	0.00419	115.5	0.00194	0.00213	46.1	0.00054	0.00083	11.55
	1,000	0.00681	0.0173	115.5	0.00280	0.00736	46.1	0.00075	0.00215	11.55

[a] For 1 Mgd cases land area for i = 0.4 fpd was rounded off to 0.1 acre and for i = 1.0 fpd was rounded off to 0.05 acre.

cavities. The spreading conditions have been deliberately chosen as the worst of the parameters, namely, land at $1,000 an acre and infiltration rate at 0.4 fpd. Even so, it is seen that spreading is by far the cheapest method of ultimate disposal.

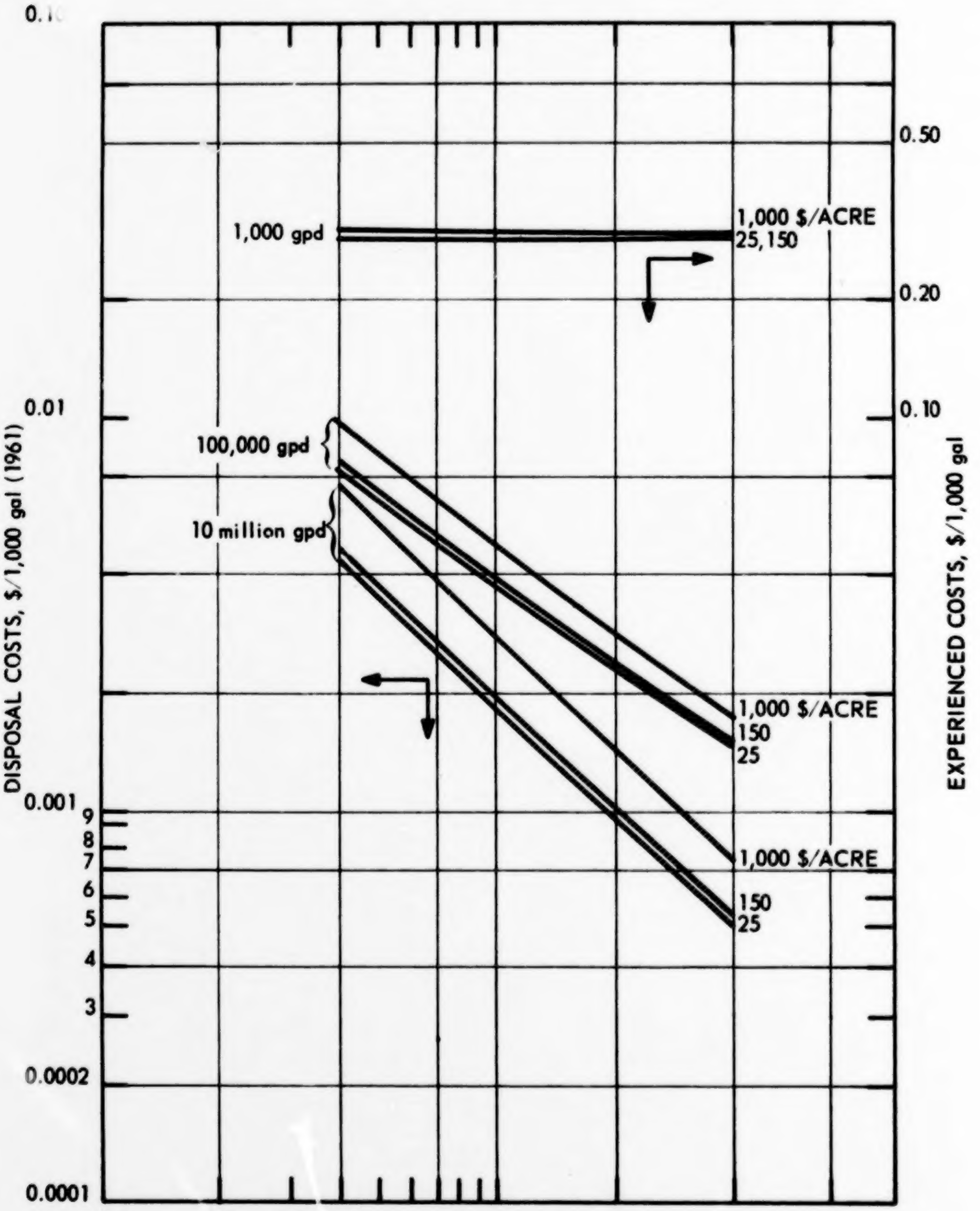

Figure 1. Unit spreading cost as a function of infiltration rate.

The cost of spreading here developed applies to spreading at the plant site. It is, however, most unlikely that spreading grounds will be available at the advanced-treatment plant site, and so a charge for conveyance of the waste to the spreading grounds must be borne. Conveyance has not yet been studied as a unit operation of ultimate disposal in this series, but data from previous preliminary studies [15, 21] make it quite clear that the cost of conveyance for even a short distance will far outweigh the costs of spreading itself. For example, the data from these previous studies adjusted to an ENR Construction Cost Index of 850 and by a short-haul factor of 150 percent for 10 miles and 200 percent for 1 mile [15] are as follows:

Capability, thousand gpd	1	100	10,000
Conveyance 10 miles, $/1,000 gal	5.90	0.59	0.059
Conveyance 1 mile, $/1,000 gal	0.78	0.078	0.0078
Spreading (0.4 fpd, $1,000/acre), Figure 3, $/1,000 gal	0.30	0.008	0.0054

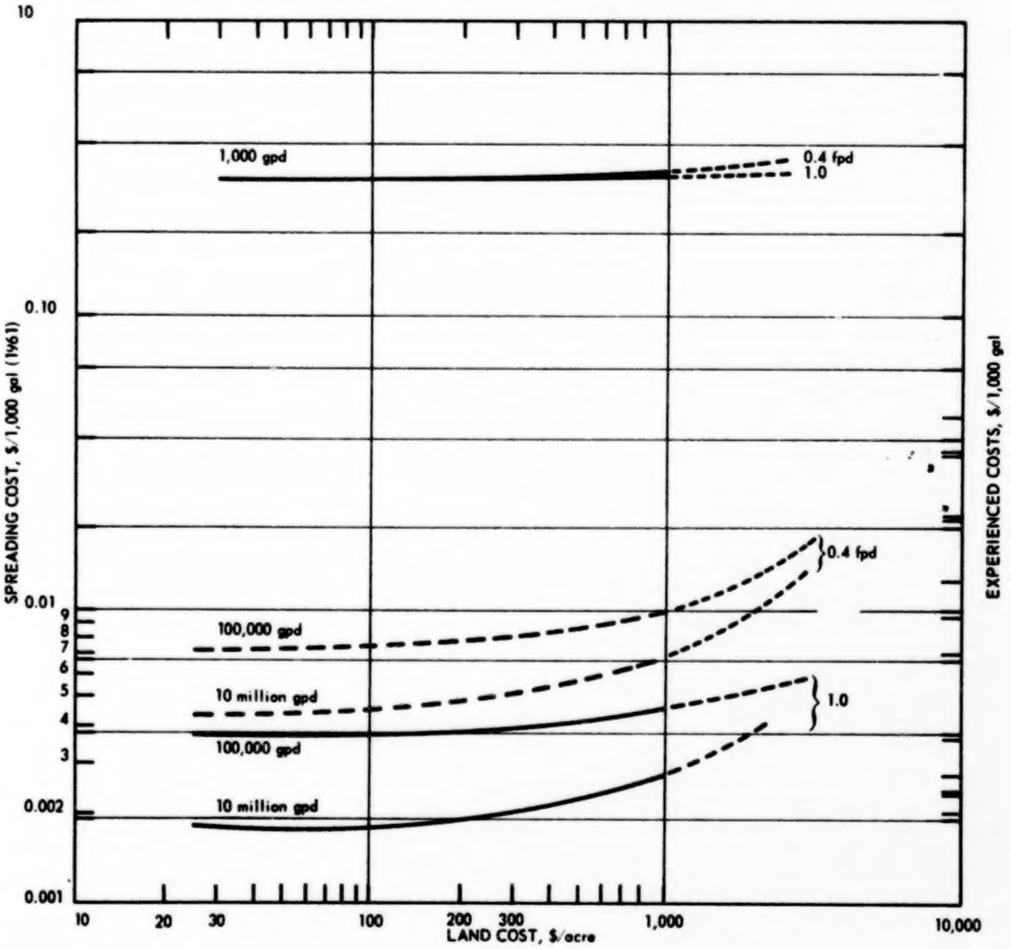

Figure 2. Unit spreading cost as a function of land cost.

Accordingly the cost of conveying to a reasonable distance from the plant and spreading will be practically identical with the cost of conveying and it would be unrealistic to make comparisons based on the cost of spreading alone. As will be shown later, the applicability of spreading as an ultimate disposal method will be extremely limited for physical reasons.

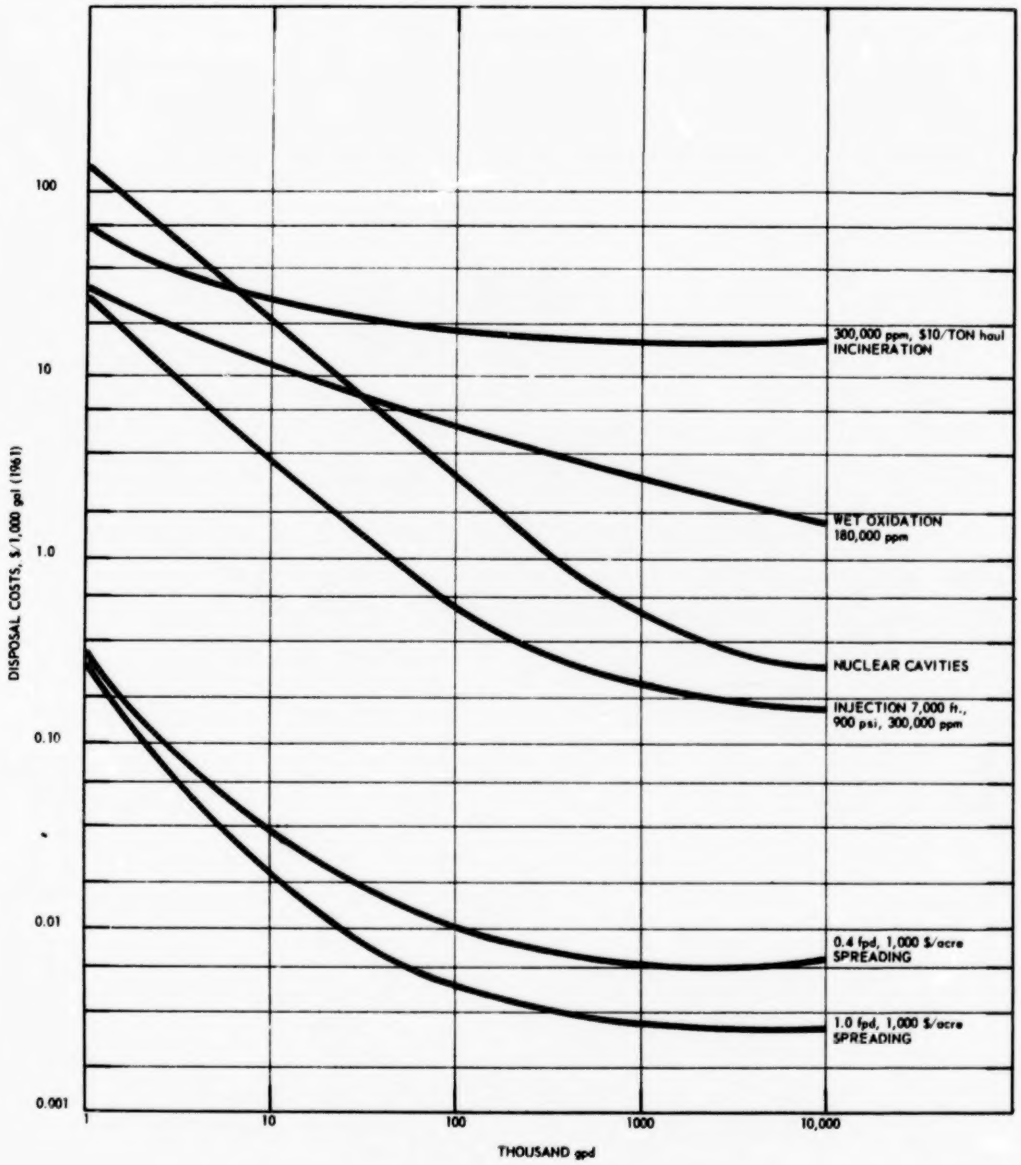

Figure 3. Unit disposal costs compared.

Spreading As An Ultimate Disposal Method

Because spreading has been shown to have such a favorable cost, it is most regrettable to conclude nonetheless that spreading as an ultimate disposal method shows very little promise in advanced treatment – so little indeed that it should not even be called an ultimate disposal method.

ULTIMATE DISPOSAL vs RECHARGE

On the other hand, spreading, including spreading of treated sewage effluents, has been practiced as a method of recharge. The liquid is spread on the ground surface, percolates through the zone of aeration, and ultimately mingles with the ground water. It has been shown that sewage effluent in passage through only a few feet of moderately fine-grained soil loses most or all of its microorganism contamination. It is true that there are literally tens of thousands of instances in which treated effluent (typically from septic tanks) has found its way into the ground water body and appeared in producing wells to constitute a ground water contamination problem owing to refractory materials, for example, ABS. Under proper conditions, however, treated sewage effluent can actually be used for recharge of ground water, as is done in Southern California. In no instance, though, is there continued recycling of ground water so recharged.

Under recycle conditions the spreading of advanced-treatment waste no longer meets the requirements for ultimate disposal. In the first place, advanced-treatment waste contains greater concentrations of contaminants than does treated sewage effluent. It may be up to saturation in the components. Second, for the most part it contains, by definition, the exotic contaminants refractory to ordinary treatment that may constitute a potential health hazard not present or not recognized in previous decades. Third, advanced-treatment connotes re-use of water and avoidance of pollution of surface waters into which wastes are currently discharged. It cannot simultaneously connote that the ground waters shall not be re-used and that they may be polluted with the waste barred to the surface waters.

THE POSSIBILITY OF PURIFICATION BY SPREADING

The connotation that spreading achieves some purification of waste liquids is in current thought. This arises from two circumstances. One is the dilution factor in the mingling of the comparatively harmless wastes with the ground water body and in the discoveries that considerable elimination of microorganisms, to the extent even of complete purification, occurs in movement through only a few feet of soil. The second circumstance is the possibility of purifying liquid radioactive wastes by percolation through large bodies of soil and the ion exchange attendant thereon.

Both of these circumstances are true and valid. Microorganism pollution is removed by percolation through soil. As to radioactive liquids, it is desired to remove only very small concentrations of certain special elements, particularly strontium, and for this purpose many soils have sufficient ion exchange capacity to fix the harmful cations and replace them with the soil cations, which provides a waste that has been freed of the harmful materials. These favorable circumstances do not, however, apply to the spreading of advanced-treatment wastes. There need be no doubt that if percolation through several feet of relatively fine soils will remove the microorganisms from secondary sewage effluent, it will also do so from advanced-treatment wastes. A possible exception to this is the chance that the high salt content of some advanced-treatment wastes might so modify the colloid structure of the clays in soils as to change appreciably their capacity for filtering out microorganisms. It is well known, for example, that certain clays are shrunk by the application of saline solutions after they have been in a fresh-water environment. For this reason, it is very difficult to keep salt brines in ordinary unlined earthen pits.

The indications from recent work[19, 20] are that a remarkable degree of removal of organic contaminants can be obtained by intermittent aerobic percolation through soil at reasonable infiltration rates. It is, however, the inorganic contaminants that pose the major problem for ultimate disposal. Some of the inorganic constituents may be affected by biological reactions and some ion exchange may occur, but in general the inorganic contaminants of the type found in advanced-treatment wastes must remain with the percolating liquors. Such ion exchange as does occur merely replaces one ion with an equivalent amount of another ion. When the removed ion is radioactive strontium and the replaced ion is sodium this can be called a purification of the liquor. The replacement of normal calcium with normal sodium, or vice versa, does not, however, constitute purification, except to the extent that the liquor may have an undesirably high or undesirably low percent sodium, in which case favorable alteration of the percent sodium, or of the "hardness," would constitute a "purification."

In any case the capacity of soil materials for large-scale ion exchange is comparatively small. Some typical cation exchange capacities of soils, kaolinite clay, halloysite clay, and oil sands are given in References 17 and 18. Of 23 samples there reported the minimum capacity in milliequivalents per 100 grams is 0.48, the maximum 20, the median 6.3. At the average density this median is equal to 0.14 milliequivalents per milliliter. In comparison a typical standard cation exchange resin will have a capacity of 2 milliequivalents per milliliter, that is, 12 to 15 times the median capacity of clays and oil sands.

Sometimes the mere size of geological formations overcomes low-intensity factors they possess, but a calculation shows that this is not the case with ion exchange in ultimate disposal. Assume a spreading basin with a given infiltration rate spreading a waste of a given concentration, considered as all NaCl, over a bed of ion exchange material of a definite thickness. The life of the bed underlying the spreading basin, that is, the number of years to complete exhaustion of the bed, is given by the following formula:

$$\text{years life} = \frac{57.4 \times \text{thickness, ft} \times \text{capacity, meq/ml}}{\text{infiltration rate, fpd} \times \text{conc NaCl, ppm}} \tag{2}$$

With the following assumptions the years of life of the exchanger bed have been computed under several different conditions:

Assumptions

Solute	NaCl
Infiltration rate	1 fpd
Bed thickness	100 ft or 1,000 ft
(Vertical percolation only)	
Cation exchange capacity	0.14 meq/ml

Then: the years life of the exchanger bed are as follows:

Concentration, ppm	100 ft thick	1,000 ft thick
300,000	0.00274	0.0274
9,000	0.0915	9.15
300	2.74	27.4

It is seen that such a bed of ion exchange material would be exhausted in a very few years at any reasonable concentrations and thicknesses. Indeed, even if the soil were made of commercial ion exchange resin, a bed 1,000 feet thick would last only a few months with 300,000 ppm waste, and a bed 100 feet thick would last only about a year with 9,000 ppm waste.

APPLICABILITY OF SPREADING

These computations indicate that spreading a waste will not result in improvement in total dissolved inorganics except a possible change of species. Hence, spreading of advanced-treatment waste must of necessity pollute the ground water beneath the spreading grounds, and this pollution will be carried by the ground water movement to other areas. If this pollution could be contained within say a cylindrical area around the spreading grounds it might constitute a form of ultimate disposal analogous to the containment of advanced-treatment waste in underground cavities. In Part 1 it was seen that the capacity of underground formations so far as pore volume is concerned is enormous. Part 1 indicates that in putting 2 million gpd into a bed of 20-foot thickness the cylindrical front will have traveled 4.75 miles in 100 years and only 23 miles in 2,500 years. There is, however, no indication that these static conditions can be achieved in practice under water table conditions such as apply in spreading. The ground water body is moving in the direction of its gravity gradient and will carry the wastes in that direction. Furthermore, the actual movement of ground water bodies, or rather of extraneous liquors within ground water bodies, is characterized by a high degree of fingering and dispersion. It is quite normal to encounter times of arrival only one-tenth of those computed on the basis of cylindrical flow. Consequently, it is obvious that spreading of advanced-treatment waste must result in pollution of the associated ground water. Hence, spreading of advanced-treatment waste constitutes ultimate disposal only under those conditions in which the ground water is considered forever unusable.

In the United States we will see a much greater use of ground water in the forthcoming years, and it would be unwise to pollute any portion of it, certainly on the scale contemplated by advanced-treatment waste disposal. This accordingly limits the applicability of spreading as an ultimate-disposal method to those areas of the country in which the ground water is not utilizable or in which no population is envisioned into the far future.

With the hopeful development of saline-water conversion the saline ground waters of the country have gradually become an important water resource. Although a considerable portion of the country is blanketed with both surface waters and ground waters that are now considered saline, these are the very areas that, having no fresh-water supplies, are most hopeful of a new water supply through conversion of saline ground and surface waters. It is hardly thinkable that the population of these areas would consider further pollution of their just-discovered resource.

Finally this appears to limit the applicability of spreading as an advanced-treatment waste disposal method to the uninhabited and uninhabitable areas of the country. Of course, these are exactly the areas that have the least need for advanced treatment. On the other hand, where communities have developed in these desert areas, the need for advanced treatment is intense, and it is very likely that for those communities ultimate disposal by spreading in nearby hydrologically closed basins may be practicable.

Areas For Further Investigation

VIGILANCE ON SPECIAL CASES

The conclusion that ultimate disposal by spreading cannot be generally applied but might be practicable in desert areas where closed hydrologic basins exist under uninhabitable land should not preclude vigilance in the rest of the country for special situations in which spreading may be applicable. As an example there may be situations in which the ground water is already so heavily polluted as to be unusable into the far future, in which case the additional load from advanced-treatment ultimate disposal could wreak no further damage.

NEED FOR IMPROVING PRESENT ESTIMATES

The estimates in the present report have been quite rough and could be strengthened in the future. For example, no cost has been considered for clearing the land of trees, brush, etc. Also, in the interest of simplicity, four separate dikes on the four sides of each pond have been estimated. In practice if 3 ponds are used, only 10 dikes rather than 12 would probably be needed since the ponds would abut one another. The figure used for maintenance costs is not well substantiated and could be improved by studies of actual incurred costs for a number of operating spreading grounds.

FATE OF ORGANIC CONTAMINANTS

There have been a reasonable number of studies, which are continuing, on the travel through soil of inorganic pollutants and of certain gross characterizations from the organic pollutants such as BOD. There is, however, a lack of information on the degree of purification achieved for specific organic pollutants, particularly those that may be of interest in advanced treatment.

There would seem to be room for further studies on travel of these pollutants and of the conditions affecting their degradation and removal in the soil. These investigations would not, however, advance ultimate disposal as such because there is no way of removing the inorganic contaminants, but they might lead toward an intermediate goal of disposal of only the organic portion of the contaminants.

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